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DOE/MA-0063 Vol. 2
Volume 2 of 6

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Cost Guide

Volume 2

Standard Procedures for Determining Revenue Requirements (Product Cost)

June 1982

U.S. Department of Energy
Assistant Secretary, Management and Administration
Office of Project and Facilities Management
Independent Cost Estimating Staff

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Washington, D.C. 20585

FOREWORD

This cost guide is the second volume on the topic of economic analysis. The first cost guide, Economic Analysis: Methods, Procedures, Life Cycle Costing, and Cost Reviewing/Validating, promotes understanding of economic analysis concepts and methodology. This, the second cost guide, was written specifically for establishing a standard within the Department for conducting economic evaluations using the revenue requirement (or product cost) methodology. By establishing a consistent set of economic factors, financial assumptions, fuel prices, and cost performance for a large number of energy alternatives, it promotes economic evaluation of energy alternatives on a consistent basis by providing the product cost of each project.

The Independent Cost Estimating (ICE) Staff reviewed several dozen studies, analyses, methodologies, and reports in preparing for this guide. One such report, the Technical Assessment Guide, which was issued by the Electric Power Research Institute (EPRI), was found to be far superior to any other reference and fully met the requirements of the Department. After careful analysis, it was decided that the Department of Energy should adopt the EPRI standard and promote its use as the best methodology applicable for evaluating research and development options for both Government and private industry. It is hoped that this action will help reduce the proliferation of less effective alternative methods for developing product cost and will promote consistency in evaluating economic benefits of future energy projects.

Comments on this guide are solicited and should be forwarded to Bobby R. Scarlett, Director, ICE Staff (MA-30.2), U.S. Department of Energy, 1000 Independence Avenue, Washington, D.C. 20585.

C. N. Mitchell, Director
Office of Project and
Facilities Management

ABSTRACT

The Department of Energy (DOE) has conducted economic analyses of alternative energy projects over the past several years. These analyses compared emerging technologies to conventional technologies and also to competing emerging technologies. The method used was to determine and compare the product costs of the technologies being assessed. This form of economic analysis is very useful because it permits comparison of dissimilar alternatives on the basis of common measures such as dollars per barrel or dollars per Btu of the end product, and provides results in terms of the money that customers would have to pay to support the energy project.

The revenue requirement (or product cost) technique has not been consistently applied within DOE. A review of the application of this technique over the past few years revealed that slightly different financial assumptions, economic factors, and scope were used. Therefore, it is not meaningful to compare results. Consistent comparison of the economic benefits of programs and projects being evaluated by the Department is essential to accomplish the assigned missions and functions. The process of reviewing much of the work accomplished by DOE and its support contractors failed to disclose a single source document or methodology which had potential application across the full range of DOE interests. However, the 1981 version of the *Technical Assessment Guide* published by the Electric Power Research Institute (EPRI) appears to have all of the necessary elements, economic factors, assumptions, and cost performance information necessary to meet the Department's needs.

A review of the document indicates that the methodology described by EPRI can be applied to almost any energy project so long as appropriate business and financial assumptions are made. The financial and business assumptions presented in EPRI technical report P-2410-SR are typical of the electric utility industry. Moreover, using a methodology already widely accepted by the utility industry, the Department can help reduce proliferation of different methods and promote the adoption of a standard. The *Technical Assessment Guide* is included in this volume with the express written consent of EPRI. The *Technical Assessment Guide* was prepared by G. H. Applegren and S. A. Vejtasa under the direction of R. W. Zeren. The document is copyrighted by EPRI, as EPRI technical report P-2410-SR, and has been reproduced for use within DOE.

This guide is divided into two parts. The first part (white pages) presents a summary of the methodology, data on fuel price projections, and cost and performance information for transmission and generation technologies. The second part (yellow pages) reflects an explanation of the economic methodology to include sample problems. Caution: 10 percent discount factors should be used for present worth calculations to conform to Office of Management and Budget guidance.

BR Scarlett

Bobby R. Scarlett, Director
Independent Cost Estimating Staff
Office of Project and
Facilities Management

ELECTRIC POWER RESEARCH INSTITUTE

EPRI

TAG™

TECHNICAL ASSESSMENT GUIDE

1981 Edition

TAG™, the Technical Assessment Guide, has been developed by EPRI to serve two functions:

1. To describe the revenue requirement method, the method EPRI uses and expects its contractors to use for the economic evaluation of R&D alternatives
2. To provide a consistent set of economic factors, financial assumptions, fuel prices, and cost performance information for use in these evaluations

The revenue requirement method is in widespread use throughout the electric utility industry. This latest edition of the TAG describes the method as it is to be used for EPRI evaluations and provides up-to-date economic factors and cost and performance data for use in the calculations involved. Consistent use of the TAG method and supporting data will enable R&D study results to be more effectively documented, communicated to, and used by EPRI, electric utilities, and others.

In some cases it will be necessary to conduct sensitivity studies using assumptions or data other than those presented in the TAG. When such studies are conducted, a baseline case using TAG methodology and data must be carried out and identified as the TAG case, and the different methodologies and assumptions used for the other cases must be clearly stated.

Consistent comparative economic studies are an essential part of EPRI's evaluation of R&D options. The TAG approach is broad in scope because EPRI serves hundreds of electric utilities and their customers. However, because EPRI is evaluating R&D options, not actual utility investments, the approach is necessarily simpler than what might be applied by an actual utility.

In the TAG, many of the economic, regulatory, financial, technical, and social factors that would be analyzed by an individual utility have been aggregated on a national average basis or deleted where their influence on R&D evaluation is judged to be minor. The cost and performance data in the TAG were developed for R&D comparison only and cannot be compared with any confidence to actual data from specific facilities. In particular, data for

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technologies not yet in commercial use are projections of cost and performance, as if the technology had already been successfully developed and were in a mature state of commercial use. Thus, use of the *TAG* methodology, data, or results derived from them for purposes other than evaluation of R&D options is inappropriate.

The concept of the *TAG* originated with a series of workshops held in 1975 and has evolved through continuing discussions within EPRI, with the electric utility industry, and with others on appropriate methods for the economic analysis of R&D alternatives. This is the fourth edition of the *TAG*. It has been substantially augmented and revised from earlier editions and is now divided into two sections:

1. *Guidelines for EPRI R&D Evaluation* (white pages)--A brief summary of the revenue requirement method and important parameters, including guidance on plant design and cost-estimating assumptions, to provide a quick reference for those already familiar with the revenue requirement technique.

2. *Background for EPRI R&D Evaluation* (yellow pages)--More detailed explanation of the revenue requirement method and a series of sample problems that demonstrate several types of economic situations.

EPRI would appreciate suggestions for improving either the economic methodology or performance data to make future editions of the *TAG* more useful. Please communicate your suggestions for changes directly to the Planning and Evaluation Division, EPRI.

Floyd L. Culler

Floyd L. Culler
President

ABSTRACT

This Technical Assessment Guide, (TAG) prepared by EPRI personnel, has been compiled for the use of EPRI staff and its contractors to provide a common basis for evaluation of electric energy R&D alternatives. The guide contains two sections:

1. GUIDELINES FOR EPRI R&D EVALUATION (white pages) -- a brief summary of the economic methodology and data on fuel price projections and cost and performance information of transmission and generation technologies
2. BACKGROUND FOR EPRI R&D EVALUATION (yellow pages) -- a more complete explanation of the economic methodology and a series of sample problems

The economic methodology described in the TAG is the revenue requirement technique, the method generally used by utilities in the economic evaluation of alternatives.

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VI

ACKNOWLEDGMENTS

The Technical Assessment Guide was prepared by G.H. Applegren and S.A. Vejtasa, under the direction of R.W. Zeren. Acknowledgment is made of substantial assistance received from various areas of EPRI, particularly from B.M. Louks and C.R. McGowin as well as other members of the EPRI Technical Evaluation Coordinating Committee and from the Ad Hoc TAG Review Subcommittee, an industry advisory committee consisting of:

L.T. Papay (Chairman)	Southern California Edison Co.
S.A. Mallard	Public Service Electric Gas Co.
W.T. Miller	Tennessee Valley Authority
J.B. Prince	Wisconsin Electric Power Co.
J.O. Rich	Salt River Project
C.L. Rudasill, Jr.	Virginia Electric and Power Co.

Inquiries related to this report should be addressed to the Manager of Technology Evaluation, EPRI.

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CONTENTS

Section | Page

GUIDELINES FOR EPRI R&D EVALUATION (white pages)

Chapter 1 R&D EVALUATION AT EPRI USING THE REVENUE REQUIREMENT TECHNIQUE 1-1
1.1 Introduction 1-1
1.2 Financial Mathematics 1-2
1.3 Investments and Expense 1-5
1.4 Revenue Requirements 1-5
1.5 Discount Rate for Present Value Analysis 1-6
1.6 The Effect of Inflation on the Discount Rate 1-6
1.7 Occurrence of Payments 1-7
1.8 Present Value of Revenue Requirements 1-7
1.9 Closing Comments 1-11

Chapter 2 PLANT DESIGN PREMISES 2-1
2.1 Introduction 2-1
2.2 Plant Duty Cycle 2-1
2.3 Plant Size 2-2
2.4 Plant Location 2-3
2.5 Plant Cost Boundary 2-4
2.6 Ambient Condition 2-4
2.7 Fuel Systems 2-5
2.8 Raw Materials Storage 2-7
2.9 Fuel Type 2-7
2.10 Fuel Variability 2-7
2.11 Water Analysis 2-8
2.12 Part-Load Performance 2-8
2.13 Load Following Capability 2-8
2.14 Loss of Plant Performance with Age 2-8
2.15 Plant Start-up Facilities 2-8
2.16 Power Plant Emissions 2-9
2.17 Design Philosophy and Equipment Sparing 2-9
2.18 Reference Design 2-9

Section		Page
Chapter 3	COST ESTIMATING PREMISES	3-1
3.1	Introduction	3-1
3.2	Cost Estimate	3-1
3.3	Capital Investment Basis	3-1
3.4	Total Plant Cost	3-1
3.5	Total Capital Requirement	3-4
3.6	Operating Costs	3-9
Chapter 4	AVAILABILITY ANALYSIS	4-1
4.1	Introduction	4-1
4.2	Definitions	4-1
4.3	Evaluations	4-5
Chapter 5	TREATMENT OF UNCERTAINTY	5-1
5.1	Introduction	5-1
5.2	Data Assumptions	5-1
5.3	Sources of Uncertainty	5-2
5.4	Interpretation and Use of Data	5-3
Chapter 6	SYSTEM ANALYSIS	6-1
6.1	Introduction	6-1
6.2	EPRI Regional System	6-1
6.3	Supply Planning Methods	6-2
6.4	Analysis of Electrical Losses	6-6
APPENDIX A	ECONOMIC PARAMETERS FOR ACTUAL PROBLEMS	App A-1
	Financial Information	App A-1
	Tables for Current Dollar Analysis	App A-2 to A-10
	Tables for Constant Dollar Analysis	App A-11 to A-19
APPENDIX B		App B-1
App B1	Economic Evaluation Cost Data	App B-1
App B2	Primary Fuel Data	App B-5
App B3	Coal-Cleaning and Synthetic Fuel Data	App B-23
App B4	Generation Data	App B-39
App B5	Energy Storage Data	App B-101
App B6	Load Management and Conservation (Not Completed)	App B-109
App B7	Electrical Transmission and Distribution	App B-111
APPENDIX C	UNCERTAINTY DATA	App C-1

Section Page

BACKGROUND FOR EPRI R&D EVALUATION (yellow Pages)

Chapter B-1 PRESENT WORTH ARITHMETIC B-1-1

B-1.1 Introduction B-1-1

B-1.2 Present Value B-1-1

B-1.3 Escalation and Inflation B-1-6

B-1.4 Levelization and Escalation B-1-9

Chapter B-2 ELECTRIC UTILITY PARAMETERS AND REVENUE REQUIREMENT ECONOMIC ANALYSIS B-2-1

B-2.1 Introduction B-2-1

B-2.2 Revenue Requirement B-2-2

B-2.3 Nature of Carrying Changes B-2-5

B-2.4 Description of Carrying Changes B-2-6

B-2.5 Property Taxes and Insurance B-2-14

B-2.6 Discount Rate B-2-14

B-2.7 Further Discussion of Escalation and Inflation B-2-14

B-2.8 Regulation and Rate Making B-2-16

B-2.9 Occurrence of Payments B-2-17

Chapter B-3 ENGINEERING ECONOMICS METHODOLOGY B-3-1

B-3.1 Introduction B-3-1

B-3.2 Economic Parameters B-3-1

B-3.3 Tables I and IV B-3-1

B-3.4 Tables II and V B-3-2

B-3.5 Tables III and VI B-3-2

B-3.6 Year by Year Carrying Charges B-3-2

B-3.7 Present Value and Levelized Carrying Charges over Book Life B-3-3

B-3.8 Present Value and Levelized Carrying Charges over Short Term B-3-5

B-3.9 Tables III and VI Described B-3-6

B-3.10 Use Levelized Revenue Requirement for Comparison B-3-7

B-3.11 Levelized Revenue Requirement Analysis over Book Life B-3-7

B-3.12 Year by Year Revenue Requirement Analysis B-3-11

B-3.13 Short-Term Analysis B-3-13

B-3.14 Break-Even Analysis B-3-15

ECONOMIC PARAMETERS FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Section		Page
	Financial Information	B-3-A-1
	Tables for Current Dollar Analysis	B-3-A-2 to B-3-A-10
	Tables for Constant Dollar Analysis	B-3-A-11 to B-3-A-19
	ECONCC Computer Program Listing	B-3-A-20
	ECONLN Computer Program Listing	B-3-A-23
Chapter B-4	UNCERTAINTY ANALYSIS	
B-4.1	Introduction	B-4-1
B-4.2	Example Problem to Illustrate Uncertainty Analysis	B-4-1
B-4.3	Summary	B-4-10
Chapter B-5	SAMPLE CALCULATIONS	
	Sample Calculation #1	B-5-I-1
	Key Words: Sunk Cost Breakeven fuel cost Less than 30-year life for new equipment Incremental fuel cost Incremental operating and maintenance cost Current dollar analysis	
	Sample Calculation #2	B-5-II-1
	Key Words: Breakeven cost Interim replacements of components at less than book life Book life less than tax recovery period Inflation Book life analysis Short-term analysis Current dollar analysis	

Section Page

Sample Calculation #3 B-5-III-1

Key Words:
- Breakeven cost
- Tax preferences for renewable resource technology
- Inflation
- Book life analysis
- Short-term analysis
- Current dollar analysis
- Constant dollar analysis

Sample Calculation #4 B-5-IV-1

Key Words:
- Overnight construction costs
- Allowance for funds during construction
- Interest during construction
- Inflation
- Progress payments
- Total plant cost
- Total plant investment

GLOSSARY 1

COMPENDIUM OF SYMBOLS 16

INDEX I-1

INTRODUCTION

The Electric Power Research Institute was formed in 1972 by the electric utility industry to conduct a nationwide research and development effort in the public interest. EPRI is funded on a voluntary basis by all segments of the electric utility industry--investor owned, municipals, cooperatives, and government entities.

An important step in the management of the Institute is the establishment of objectives and priorities for our research and development programs. To assist in this end, the *Technical Assessment Guide* (TAG) provides a consistent economic methodology for determining the relative cost to electric utility customers of the potential results of alternative R&D efforts. In addition, TAG provides the cost and performance data and financial information needed to carry out such analysis. The target audience of the TAG is the EPRI staff and contractors who prepare engineering economic analyses for EPRI.

EPRI has adapted the revenue requirement method, widely used by electric utilities for economic analysis of R&D options. The *Technical Assessment Guide* describes the implementation of this method, presenting techniques that can be applied in a consistent manner by the staff and those under contract to the Electric Power Research Institute.

While broad in coverage, TAG is nevertheless limited in its application. Its intent is:

- To publish a consistent methodology for engineering economic evaluations that are encountered in the development of priorities and goals at EPRI
- To present consistent cost and performance data of reference technologies for comparison with other technologies
- To provide consistent financial information, based on current average values in use in the industry for use in EPRI analyses

On the other hand, the methodology of the *Technical Assessment Guide* has certain limitations.

- The method is simplified from the revenue requirement analysis that would be used by an actual utility. Many utility-specific factors have been aggregated into national averages or, where their influence on R&D evaluation is judged to be minor, deleted.
- Many factors that influence actual utility decision making, such as accounting, regulatory, rate making, technical, operating, financial, and social issues, are not addressed.
- The cost and performance data are for R&D comparisons only and are not intended to represent specific facilities. The data should not be used as benchmarks for comparison with actual construction projects or operating plants. In particular, the data for the technologies not yet in commercial use are projections of cost and performance as if the technology had been successfully developed and were in a mature state of commercial use.

Nevertheless, the revenue requirement method provides important information to support the establishment of R&D objectives and priorities at EPRI.

This guide is composed of two sections:

- GUIDELINES FOR EPRI R&D EVALUATION (white paper)
- BACKGROUND FOR EPRI R&D EVALUATION (yellow paper)

The Guideline Section provides a summary of the revenue requirement methodology for a reference guide for those familiar with the technique. Chapter 1 presents the procedures for making revenue requirement economic analyses and includes the basic formulas. Chapters 2 and 3 provide guidance for consistent and complete plant designs and operating cost estimates. Chapter 4 develops a method for estimating outage rates for new technologies, and Chapter 5 addresses uncertainties in these data. Chapter 6 considers utility system analysis. Economic factors are presented in Appendix A, plant and operating costs in Appendix B, and uncertainty data in Appendix C.

The Background Section (Prefix B) explains the theory and application of the revenue requirement technique in more detail. Chapters B-1 through B-3 contain a brief explanation of present worth arithmetic, the revenue requirement methodology and economic analyses that are appropriate for both the short range and long range time frames that are presented in Chapter 1. Chapter B-4 describes a simple decision analysis that makes use of estimates of data uncertainty, and Chapter B-5 is a set of sample calculations.

[redacted]

The analyst has the choice of making an economic analysis in current dollars by including the effect of inflation or in constant dollars by not including inflation. In general, engineering economic analyses are made in current dollars because, in a society of changing dollar values, this option affords more insight into effects on utility customers in the future. However, the constant dollar analysis does offer a view of changing cost patterns without the inflation effect and, therefore, may be appropriate in some cases.

Working in constant dollars has the advantage of making the analysis essentially independent of the inflation rate. Cost trends due to real price escalation are clearly visible. Constant dollar analyses referenced to a nearby point in time result in costs presented in dollars with a purchasing power close to current experience, and value judgements are easier to make. For example, coal priced at $1.65/10^6 Btu in December 1980 has a price of $8.43/10^6 Btu in the year 2000 dollars if an average annual inflation rate of 8.5%/yr is assumed. If the coal price is quoted in December 1980 dollars, it has more intuitive meaning to the reader than if it is quoted in year 2000 dollars.

The major drawback of using constant dollars is that when future expenditures are actually planned, they should be based on prices and costs that are actually expected to occur (current dollars) in order to budget sufficient funds to cover these expenses. Hence the constant dollar analysis tends to be somewhat artificial, whereas the current dollar analysis reflects the actual numerical values of the various cost accounts.

Forecast data from the latest edition of the EPRI Overview and Strategy document (published each September) should be used as appropriate unless specific utility or regional data are available or required for particular analyses.

GUIDELINES
FOR
EPRI
R&D
EVALUATION

4

Chapter 1

R&D EVALUATION AT EPRI USING THE REVENUE REQUIREMENT TECHNIQUE

1.1 INTRODUCTION

This chapter is a collection of the formulas needed to make the revenue requirement analysis that patterns, for EPRI purposes, the process for the economic evaluation of engineering alternatives in the electric utility industry. More complete background material for this information will be found in Chapters B-1 through B-3 of the yellow pages.

Before stating the required formula, it would be appropriate to review several important concepts. A typical economic analysis is the result of three distinct and separate efforts. The first is to select alternatives and the second is to estimate costs. Only after these have been completed can the final effort, the numerical analysis, be undertaken.

In any engineering study all valid alternatives should be considered. Alternatives must represent legitimate courses of action. Some alternatives may be eliminated by the application of common sense or reasoned judgment, but extreme care must be exercised in this regard because important ramifications of a particular alternative may be lost because of a too hasty perusal of the problem. Some general principles can assist in the proper selection of alternatives:

- Equal services must be presented by each alternative unless the differences are quantified, as for example, in the amount of energy supplied or in equipment availability.
- Projecting into the future based on the past requires care because past trends need not continue in the future if there are basic changes in the cause and effect relationships.
- The alternative to retire or to replace an existing plant item at some point in time is not to never retire or replace but to retire or replace at another point in time.
- In general, if a utility requires generating capacity at a future point in time, the capacity must be provided by additions to plant, or by

[redacted]

purchasing power, or by some combination, although the need for capacity may be reduced by an effective load conservation effort.

- Alternatives that may at first seem to be equal may infact contain important inequalities. Consider for example, the differences between one MW of base load generation and one MW of peaking generation.

The topic of cost estimating is covered in Chapters 2 and 3. The several technologies presented in Appendix B constitute a set of reference plants for comparative purposes. The uncertainty of plant and operating costs of candidate technologies and the necessary tests of the sensitivity of the final outcome to these uncertainties, along with the determination of reliability of candidate technologies are important steps in the technical assessment process at EPRI and are covered in Chapters 4 and 5.

1.2 FINANCIAL MATHEMATICS

Let us now begin a brief review of the financial mathematics needed to perform economic comparisons at EPRI. The numerical analysis for the evaluation of R&D alternatives at EPRI involves the use of several relatively straightforward mathematical formula and symbols. These are presented below and are more fully discussed in the yellow pages.

1.2.1 Present Value of a Single Sum

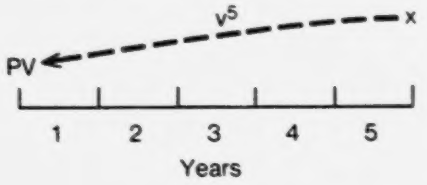
The discount rate $\underline{i}$, is the time value of money in the time period $\underline{n}$. The present value $\underline{PV}$ of a single amount $\underline{x}$ made $\underline{n}$ time periods in the future at a discount rate $\underline{i}$ per time period is determined by the formula

$$PV = xv^n \qquad 1.2.1\text{-}1$$

where

$$v^n = \frac{1}{(1+i)^n} \qquad 1.2.1\text{-}2$$

The use is illustrated by a time diagram. Suppose that $\underline{x}$ occurs 5 years in the future, and we are to determine the present value of $\underline{x}$ at the beginning of the first year.



$$PV = xv^5 \qquad 1.2.1\text{-}3$$

The present value n years in the future of a single amount today is determined by multiplying the dollars today by the reciprocal of v^n.

1.2.2 Present Value of a Uniform Series

The present value PV of a uniform series x per time period that extends n time periods in the future at a rate of i per time period is determined by the formula

$$PV = xa_n \tag{1.2.2-1}$$

where

$$a_n = v + v^2 + \cdots + v^n \tag{1.2.2-2}$$

or

$$a_n = \frac{1-v^n}{i} \tag{1.2.2-3}$$

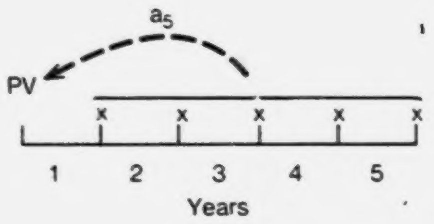
or

$$a_n = \frac{(1+i)^n - 1}{i\,(1+i)^n} \tag{1.2.2-4}$$

or

$$a_n = \left(\frac{1-v^n}{1-v}\right)v \tag{1.2.2-5}$$

The use is illustrated by a time diagram. Suppose that there is a uniform series consisting of an amount x at the end of each year for 5 years and we are to determine the present value of the uniform series at the beginning of the first year.



$$PV = xa_5 \tag{1.2.2-2}$$

Note that the present value of a uniform series using the a_n factor of 1.2.2-2 through 1.2.2-5 is always at a point in time that is one time period prior to the first transaction in the series.

To convert a single sum at one point in time to a uniform time series use the reciprocal of the a_n factor. In this case, the first term of the series will always occur one time period after the single sum.

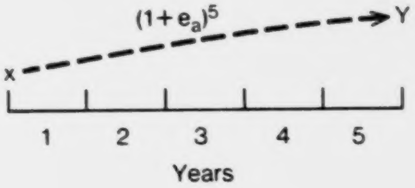
1.2.3 Escalation and Inflation

The annual inflation rate e_i is the rate in rise in price caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal value. The real escalation rate e_r is the annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, or improvements in the state of the art (negative rate). Real escalation is independent and exclusive of inflation.

The apparent annual escalation rate e_a is the total annual rate of increase in price level and includes the effects of both inflation and real escalation. It is equal to

$$e_a = (1+e_r)(1+e_i)-1 \qquad 1.2.3\text{-}1$$

The use is illustrated by a time diagram. Suppose that there is an amount x at the beginning of the first year, subject to an apparent escalation rate, and we determine the price level Y at the end of the fifth year.



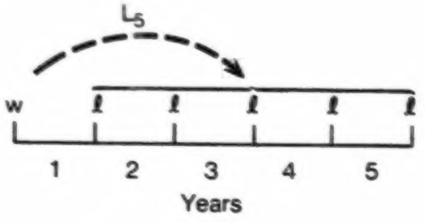
$$Y = x(1+e_a)^5 \qquad 1.2.3\text{-}2$$

Note that to express a sum of money subject to escalation in terms of dollars at another point in time the apparent escalation rate e_a is used. To express a sum of money in a different reference year the discount rate i is used.

1.2.4 Levelization and Escalation

The levelization factor L_n determines the equivalent levelized value ℓ of a series of n payments that is uniform over time except for a constant apparent escalation rate. The price level of the series at the beginning of the first year is w.

The use is illustrated by a time diagram.



$$\ell = w_t L_5 \qquad 1.2.4\text{-}1$$

The concepts presented in Section 1.2.1 are covered in greater detail in Chapter B-1 of the yellow pages. Values of the factors $\underline{v}^n$, $\underline{a}_n$ and $\underline{L}_n$ for working actual problems may be found in Appendix A.

1.3 INVESTMENTS AND EXPENSE

An investment is an expenditure which results in a unit of plant that is of long term use. In a revenue requirement analysis, the money to pay for an investment must come from outside debt and equity financing.

Investments include, but are not limited to, the physical plant of a utility, such as generating units, and the transmission and distribution systems.

Expenses are all of the expenditures that are not classed as investment items, including operating and maintenance charges and fuel. Expenses are paid directly from revenue. While investments are paid from new debt and equity securities, the return that is due to debt and equity security holders, book depreciation, income taxes, local property taxes, and insurance are also taken from revenue.

1.4 REVENUE REQUIREMENTS

The revenue requirement method used to evaluate R&D alternatives at EPRI is the method generally used in the electric utility industry to assess the economic consequences of alternatives.

The revenue requirement is the total revenue that must be collected from customers to compensate a utility for all expenditures associated with the implementation of an alternative decision involving money.

$$RR = \text{carrying charges} + \text{expenses}$$

[redacted]

The carrying charge (CC) is the revenue obligation needed to support an investment item and is equal to the sum of return on debt (R_D), return on equity (R_E), federal and state income tax liability (T), book depreciation (D_B), property taxes (PT) and insurance (I).

$$CC = R_D + R_E + T + D_B + PT + I$$

In general, in the year i, the annual carrying charge will be greater than the annual carrying charge in year $i+1$ because of the effect of book depreciation.

1.5 DISCOUNT RATE FOR PRESENT VALUE ANALYSIS

The discount rate i for present value calculations is the weighted cost of capital and is equal to the sum of the return on debt and the return on equity. Page 1 of Appendix A of this section lists actual economic factors that are to be used in making revenue requirement studies at EPRI. Appendix A is revised when dictated by changing conditions.

1.6 THE EFFECT OF INFLATION ON THE DISCOUNT RATE

Continuing the discussion of 1.2.3, the inflation rate has a direct relationship on the discount rate i. If e_i is the inflation rate and c is the weighted cost of capital in the absence of inflation,

$$i = (1+c)(1+e_i) - 1 \qquad 1.6\text{-}1$$

It is possible that high rates of inflation may change the value of the constant dollar discount rate, c, since this value is based on a certain level of investment risk and high inflation rates may change the level of risk. However, for EPRI purposes, it is assumed that an increase in the inflation rate e_i causes a corresponding increase in the discount rate i as shown in Equation 1.6-1, and the value of c remains constant.

A present value analysis can be performed using current dollars in which investments before they are capitalized and expenses inflate according to the inflation rate e_i. The carrying charges do not inflate, since once the investment is capitalized, these charges are fixed. A current dollar analysis requires the use of a discount rate equal to the cost of money at the prevailing rate of inflation.

On the other hand, if costs are kept in constant dollars rather than allowed to inflate, the discount rate must be the weighted cost of capital in the absence of inflation (Equation 1.6-1).

The tables to use for current dollar and constant dollar analysis are indicated on Page 1 of Appendix A.

1.7 OCCURRENCE OF PAYMENTS

For convenience in making economic studies, it is assumed that all investments will be made at the beginning (January 1) of a year based on cost estimates referenced to December 31 of the previous year and all carrying charges, and unless otherwise stated, all expense items are made at the end of the year. The concepts contained in Sections 1.3 through 1.7 are covered in greater detail in Chapter B-2 (yellow pages).

1.8 PRESENT VALUE OF REVENUE REQUIREMENTS

The concepts of present value arithmetic and revenue requirements that have been presented earlier in this chapter are combined to obtain the present value of revenue requirements.

1.8.1 Book Life Analysis

The present value of carrying charges $V_{m,n}$ is merely the sum of the present value of each of the annual carrying charges over the book life of an investment.

$$V_{m,n} = CC_1 v^1 + CC_2 v^2 + \cdots + CC_n v^n \qquad 1.8\text{-}1$$

where m is the tax recovery class and n is the book life. The present value $V_{m,n}$ can be levelized by dividing by the a_n factor.

Thus,

$$P_{m,n} = \frac{V_{m,n}}{a_n} \qquad 1.8\text{-}1$$

where $P_{m,n}$ is the levelized carrying charges of a plant item with an m year tax recovery class and n year book life. The tax recovery class for various categories of plant together with the proper financial factor tables are listed on the first page of Appendix A. The Internal Revenue Code has evolved through the years to the point where substantial tax preferences (deferred income taxes and the investment tax credit) are available to electric utilities. Appendix A tables show carrying charges with and without tax preferences.

Because it now appears that tax preferences are likely to continue, EPRI currently recommends that they be included in economic analyses performed for EPRI. It may be appropriate to make an analysis both with and without the tax preferences to show future economic consequences of a candidate technology if the revenue code is substantially revised. Analyses done without tax preferences should be clearly labeled.

A book life analysis is the present value of revenue requirements or levelized revenue requirement over the book life of an alternative (carrying charges plus expenses).

For a typical Alternative A,

Present Value Revenue Requirement ($PVRR_A$)

$$PVRR_A = (\text{Investment})\,(V_{m,n}) + \Sigma\,(\text{Expenses})\,(L_n)\,(a_n)$$

Levelized Revenue Requirement (LRR_A)

$$LRR_A = (\text{Investment})P_{m,n} + \Sigma\,(\text{Expenses})\,(L_n)$$

where,

Investment = Total Capital Requirement (see Chapter 3)

Expenses = All appropriate expenditures

$V_{m,n}$ and $P_{m,n}$ = Appropriate factors from Appendix A for a plant item with an $\underline{m}$ year tax recovery class and $\underline{n}$ year book life

L_n = Levelizing factor from Appendix A based on an appropriate real escalation rate $\underline{e_r}$, and inflation rate $\underline{e_i}$ for each expense

a_n = Present worth factor for a uniform series from Appendix A

The levelized revenue requirement is commonly used. For generating unit options, the results are usually stated in levelized annual cost per kWh of energy delivered.

1.8.2 Year-by-Year Analysis

The mechanics of the book life calculation of Section 1.8.1 is such that actual revenue requirements in any particular year cannot be identified. Significant differences in revenue requirements on a year-by-year basis that might weigh heavily on the decision making process are not addressed. The year-by-year analysis, in which actual revenue streams are compared on an annual basis (but not present valued), overcomes this problem.

Generally, it is best to arrange a year-by-year analysis in columnar form for each alternative. See Chapter B-3 for an example.

Sample Year-by-Year Analysis
for one Alternative

Carrying Charge			Expenses (3)		Total Revenue Requirement
Year	Rate (1)	$(2)	Escalation	$	S CC + Expense

(1) From the proper Table of Appendix A
(2) Rate times original investment
(3) Will require several Expense sets if several real escalation rates are involved.

1.8.3 Short Term Analysis

While the year-by-year analysis of Section 1.8.2 provides valuable information about the comparative costs for each alternative, the analysis is laborious and produces an array of numbers. A less cumbersome technique that produces a single number is called the short term analysis. This analysis uses the same financial mathematics discussed in Section 1.8.1 and does not change the book life or tax recovery class; it is simply a look at the first several years of a long life project.

The period or duration of the short term analysis deserves some comment. In today's financial environment, many utilities face a cash shortage brought about by continuing inflation and inadequate rates. The analyst must be cognizant of the potential impact of various alternatives on the near term financial condition of a utility.

Some utilities have adopted the policy that any alternative that does not show a revenue requirement advantage in the first one-fourth to one-third of its life or that causes a significant deficit in the first 10 years of life compared to the other alternatives would not be the proper economic choice. Also, unforeseen modifications brought about by technical obsolescence, changing regulatory constraints, public policies, etc., may be such that "long range" advantages may never materialize.

The short-term analysis considers only the first $\underline{f}$ years of the book life analysis of Section 1.8.1. Accordingly, for a typical Alternative A,

Present Value Analysis

$$\text{1st f year PVRR}_A = (\text{Investment})\,(V_{f,m,n}) + \Sigma\,(\text{Expenses})\,(L_f)\,(a_f)$$

Levelized Analysis

$$\text{1st f year LRR}_A = (\text{Investment})\,P_{f,m,n} + \Sigma\,(\text{Expenses})\,(L_f)$$

where,

Investment = Total Capital Requirement (see Chapter 3)

Expenses = All appropriate expenditures

$V_{f,m,n}$ and $P_{f,m,n}$ = Appropriate factors from Appendix A for the first f years of a plant item with an $\underline{m}$ year tax recovery class and $\underline{n}$ year book life

L_f = Levelizing factor from Appendix A based on an appropriate real escalation rate $\underline{e_r}$, and inflation rate $\underline{e_i}$ for each expense

a_f = Present worth factor for a uniform series from Appendix A

Today, many electric utilities consider the first 10 years in short-term analyses. Unless conditions dictate otherwise, short term analyses made for EPRI should use the first 10 years.

1.8.4 Break Even Analysis

The break even analysis determines the year in which the cumulative present value of revenue requirements of two alternatives are equal and usually involves an iterative process. The general expressions are indicated below:

$$PVRR_A = PVRR_B$$

$$(\text{Investment}_A)\ (V_{f,m,n}) + \Sigma\ (\text{Expenses}_A)\ (L_f)a_f = (\text{Investment}_B)\ (V_{f,m,n}) + \Sigma\ (\text{Expenses}_B)\ (L_f)a_f$$

where,

Investment = Total Capital Requirement (see Chapter 3)

Expenses = Appropriate expenditures

$V_{f,m,n}$ = Appropriate factor from Appendix A of the first $\underline{f}$ years of a plant item with an $\underline{m}$ year tax recovery period and an $\underline{n}$ year book life

L_f = Levelizing factor from Appendix A, or calculated as required, based on an appropriate real escalation rate $\underline{e_r}$, and an inflation rate $\underline{e_i}$ for each expense

a_f = Present worth factor for a uniform series from Appendix A

Using this relationship, the break-even point $\underline{f}$ is determined.

The concepts presented in Section 1.8 are covered in greater detail in Chapter B-3 (yellow pages).

1.9 CLOSING COMMENTS

Carrying changes on existing plant are sunk costs. They are not included in an economic analysis since these charges were incurred when a prior decision was made and will continue as an obligation regardless of any current course of action.

If an alternative does not show an economic advantage in the early years, electric utility management likely will look unfavorably on that alternative, even though calculations may show a long term economic advantage. The uncertainties in the utility operating climate have become sufficiently great so as to increase the risk that long term advantages may never be achieved.

In spite of the short term economic advantage of some alternatives, EPRI may also explore those alternatives that have only a long term economic advantage. EPRI's function is to look ahead and to develop technologies that will meet the future needs of the electric utility industry and its customers. Short term economic considerations are important, however, and may affect research priorities. In any event, both the long and short term economic consequences of a technology can be determined using the methodology presented in this guide.

Chapter 2

PLANT DESIGN PREMISES ·

2.1 INTRODUCTION

The future value of a new technology is an important factor in determining research and development priorities. Comparing conceptual designs and cost estimates of a new technology with those of a currently available technology gives insight into the cost incentives and technical issues associated with the new technology. The conceptual designs and cost estimates are generally prepared assuming the technology is in a "mature" state of development.

This chapter defines the design premises that are to be used in EPRI-sponsored design studies of power plants. In the future, premises for other electric utility facilities will be provided. Design alternatives must be prepared with a consistent set of premises that cover site conditions, climatic conditions, plant capacity, plant storage, fuel types, and many other areas. Tables with reference coal analyses and other design information are located at the end of this chapter. The treatment of contingencies, operating costs, and other economic variables is discussed in Chapter 3.

The conceptual designs prepared as part of EPRI studies must incorporate the design premises given in this chapter. For special cases where the recommendations here do not apply or where specific additional premises are required, modified premises should be developed in cooperation with the Planning and Evaluation Division.

2.2 PLANT DUTY CYCLE.

Specific design premises are strongly affected by the expected duty cycle of the power plant. For example, plants expected to be baseloaded generally will require larger fuel storage facilities compared to intermediate or peaking plants. Therefore, for the purposes of this guide, power plant types are characterized by a nominal annual capacity factor as shown in the following table.

Plant Duty Cycle	Nominal Annual Capacity Factor	Generic Characteristics Cost	Performance
Base	65%	Low fuel cost, high capital cost	Designed for high reliability and high efficency
Intermediate	30%	Intermediate to high capital cost, intermediate fuel cost	Flexible performance
Peaking	10%	Low capital cost, high fuel cost	Flexible performance, quick starting, short construction lead time

It should be emphasized that these capacity factors are nominal values to be used as the basis for conceptual designs and to represent lifetime levelized values. Actual plant capacity factors in similar duty cycles may vary widely depending on actual outage rates, individual system load characteristics, and economic dispatch requirements.

2.3 PLANT SIZE

For consistency in generation-system planning studies, which are discussed in Chapter 6, arbitrary differences in unit sizes among competing technologies should be minimized. In general, technologies limited to large unit sizes may suffer economic penalties in reliability considerations and in matching generation additions to system load growth. Therefore, the unit size selected for design studies must consider the compatibility of the unit with the generating system and not merely reflect the economies of scale.

Utilities generally install two or more units at a given plant site. If the units are built in sequence, the favorable scheduling of construction labor and the sharing of common facilities results in the average cost (expressed in constant \$/kW) for two units being less than the cost for a single unit. Based on these considerations, the following specifications will apply for EPRI purposes:

Plant Duty Cycle	Nominal Plant Fuel	Nominal Plant Size (MW)	Nominal Unit Size (MW)
Base	Nuclear	1000 to 2000	1000
	Coal[a]	1000 to 2000	500 to 1000
	Geothermal	100	50
Intermediate (central station)	Solid fuels[b]	500 to 1000	250 to 500
	Fluid fuels[c]	500	250
Intermediate (dispersed)[d]	Fluid fuels[c]	50	5-25
Peaking (central station)	Fluid fuels[c] Solid fuels[b]	100 to 200 500 to 1000	50 to 100 250 to 500
Peaking (dispersed)[e]	Fluid fuels[c]	25	5 to 25
Storage (dispersed)[e]	25	5-25	
Storage (central)	500 to 1000	250 to 500	

---

[a] Includes coal boilers, gasification and other direct coal consuming technologies.

[b] Includes coal and other solid fuels such as solid solvent refined coal.

[c] Liquid and gaseous fuels.

[d] E.g., fuel cells.

[e] E.g., batteries.

Due to limitations in the availability of certain sizes of commercial equipment, it may be necessary to base the design on unit or plant sizes that are 10 to 20% higher or lower than the nominal values shown.

2.4 PLANT LOCATION

The base location is the Wisconsin-Illinois area in the West Central Region as defined in Appendix B. The site is assumed to be clear and level with no special problems. The site is in Seismic Zone 1 at an elevation of 600 feet above mean sea level. A river for raw water supply is assumed to be within six miles of the plant site. Pile-type foundations are to be assumed in this region.

2.5 PLANT COST BOUNDARY

The plant cost boundary includes all facilities needed to operate the plant (shops, offices, cafeteria, fuel unloading and storage equipment, water-intake structures, waste-treating facilities, etc.). The plant cost boundary includes the high-voltage bushing of the generation step-up transformer, but the switchyard and associated transmission lines are outside the plant cost boundary and are not included in the cost estimate.

Solid-waste (ash and scrubber sludge) disposal is included within the plant cost boundary. For nuclear plants, sufficient storage for spent fuel for the life of the plant is to be included.

2.6 AMBIENT CONDITIONS

Although the ambient conditions will vary greatly from site to site, the following conditions are to be used for consistency.

2.6.1 Design Conditions for Average Operation

The following ambient conditions are to be used for cycle optimization, material balances, thermal efficiency calculations, etc.

	Baseload	Peaking and Intermediate
Dry-bulb temperature	60°F[a]	85°F[b]
Wet-bulb temperature	52°F	75°F
Atmospheric pressure	14.4 psia	14.4 psia

---

[a] Based on annual average maximum daily temperature for Chicago area.

[b] Based on June to August normal maximum daily temperature for Chicago area.

The intermediate and peaking plants operate primarily in the daytime, therefore, experience a higher ambient temperature than the baseload plants. An approximation of this temperature difference is given in the above table and is to be used for consistency.

2.6.2 Design Conditions for Maximum Ambient-Temperature Operation

The plant design must include the capability of achieving rated output (e.g., 1000 MW) at maximum ambient temperature, although efficiency may be reduced. Alternatively, the derated output of the plant must be calculated, and costs must be presented on the basis of $/kW of derated capacity under maximum temperature conditions. These following conditions are based on a summer peak.

	Baseload	Peaking and Intermediate
Maximum dry-bulb Temperature	95°F	95°F
Wet-bulb temperature	75°F	75°F
Atmospheric pressure	14.4 psia	14.4 psia

Cooling-water system requirements are based on these maximum temperature conditions. Mechanical-draft cooling towers should be used unless the design includes a study of different types of cooling systems. Designs should not be based on once-through cooling.

2.6.3 Minimum Temperature

For freeze protection and winterization considerations, the Design Minimum Temperature is -20°F.

2.7 FUEL SYSTEMS

2.7.1 Fuel Delivery

The following fuel-delivery systems are to be used.

Plant Duty Cycle	Fuel Type	Delivery-Receiving System Design
Base	Coal	Unit train delivery with rotary dump hopper cars
Intermediate (central station)	Solid fuel (includes coal)	Unit train delivery with rotary-dump hopper cars
	Liquid fuel	Tank car unloading facilities
Intermediate (dispersed)	Liquid fuel	Tank truck unloading facilities
Peaking	Liquid fuel facilities	Tank truck unloading

The facilities should be sized for maximum unloading times of four hours for 100 car unit trains or 15 minutes per car for tank car/tank truck facilities.

2.7.2 Fuel Storage Capacity

Design of the fuel storage system size should be consistent with the maximum capacity shown below.

Nominal Duty Cycle	Storage Capacity[a]
Baseload[b]	90-day supply at 100% capacity factor
Intermediate[c]	60-day supply at 100% capacity factor
Peaking	10-day supply at 100% capacity factor

---

[a] This specification refers to the total *size* of the storage system. The average *amount* of fuel in storage is addressed in the EPRI cost-estimating premises in Chapter 3.

[b] Excluding nuclear.

[c] Solid and liquid fuels.

2.8 RAW MATERIALS STORAGE

The raw material (such as limestone) storage areas are to be designed to hold a 30-day supply at 100% capacity factor. Covered storage is required for materials that dust or degrade.

Normally, raw water storage is not included. If water storage is necessary, the facilities are to be sized for a 60-day supply at 100% capacity factor.

2.9 FUEL TYPE

2.9.1 Coal-Fired Plants

The reference fuel should be an Illinois No. 6 coal. This coal is recommended for base-case designs because (1) it has been used previously in many designs sponsored by EPRI and others, (2) it is readily available with a large resource base in the central part of the country, and (3) due to its relatively high sulfur and ash content, it is a fairly difficult coal to consume in a power plant and still have it be able to meet emission standards. The standard coal analysis is shown in Table 2-1.

If a separate case using a western subbituminous coal or a south-central lignite is to be included, then use the standard analysis in Table 2-2 or Table 2-3.

2.9.2 Fluid-Fuel-Fired Plants

Typical fuel specifications are given in Table 2-4 for several different coal-derived liquid fuels, solid solvent-refined coal (SRC-I), a representative No. 2 fuel oil from petroleum, and an intermediate-Btu synthetic gas. One of these fuels (except SRC-I) may be selected as the reference fuel for a fluid-fuel-fired plant.

2.10 FUEL VARIABILITY

A coal-fired plant must be designed to accommodate the variability in sulfur content and other properties of the chosen fuel. The variabilities for the reference fuels are given in Tables 2-1, 2-2, and 2-3. The material balance and efficiency for normal operation is computed on the average (expected) fuel analysis.

[redacted]

2.11 WATER ANALYSIS

The recommended water analysis for the raw water is shown in Table 2-5.

2.12 PART-LOAD PERFORMANCE

The base performance calculations are to be developed for 100% of rated output. The plant performance (heat rate, etc.) also should be computed for at least one part-load condition, preferably at about 50% of rated output. An estimate must be made of the minimum-load (as percentage of full load) level and of the performance at minimum load.

The part-load performance of a modular plant is to be based on all the modules operating at part load. The shutdown of some modules should not be included unless the modules can be restarted with essentially no time delay (i.e., less than 30 minutes).

2.13 LOAD-FOLLOWING CAPABILITY

The load-following capability of the plant should be estimated in terms of percent of load-change/unit time in the range of 50 to 100% of load. A load-change capability of at least 1%/minute is recommended for baseload plants. Peaking plants should be able to go from a cold start to full load in 30 minutes. Plants used as spinning reserve must be able to produce full power in 10 minutes.

2.14 LOSS OF PLANT PERFORMANCE WITH AGE

If certain plant components are expected to experience a relatively rapid loss in performance with time, then the design should include spare capacity or other means of counteracting this potential performance loss.

For example, in pulverized-coal-fired plants, the flue gas treating equipment and induced draft fans are normally oversized to account for eventual air infiltration leaks in the air preheater. These air leaks may eventually increase the flue gas rate by 20% or more above the initial value.

2.15 PLANT STARTUP FACILITIES

Electric power is assumed to be available at the plant site for startup purposes. Other facilities needed for plant startup are to be included in the design. Care should be taken so that the effect of complex heat recovery and plant integration systems on plant startup is realistically estimated.

2.16 POWER PLANT EMISSIONS

All coal-based plants are to be designed to conform to the promulgated 1979 New Source Performance Standards (NSPS). Understanding the sensitivity of the design configuration and cost to possible changes in emission standards is very desirable. Table 2-6 presents a set of more stringent standards for consistency in determining this sensitivity. These stringent standards are representative of conditions that may face plants being sited in prevention of significant deterioration (PSD) areas, noncompliance areas, or areas with special local regulations.

2.17 DESIGN PHILOSOPHY AND EQUIPMENT SPARING

Conventional, commercially available equipment should be selected for all plant sections unless otherwise specified by the EPRI project manager. In those plant sections that include advanced technology, the degree of extrapolation from commercial experience should be clearly identified.

Example: Sludge Filtration Rates

	gal/min/ft^2 (total surface)
Commercial experience (give reference)	20
New filter concept	
• Pilot-scale tests	35
• Projected commercial performance	40

The specification of spare equipment should be consistent with that of similar commercial plants which can achieve a 90% availability exclusive of planned maintenance.

Capital-cost versus operating-cost trade-off decisions should be based on a life cycle analysis using the EPRI cost-estimating premises presented in Chapter 3.

2.18 REFERENCE DESIGN

Whenever possible, the contractor should also provide a reference plant design that can be used to calibrate the estimate for a new technology. The reference design for baseload plants is a conventional, pulverized coal-fired power plant with a limestone FGD system. The reference plant should have the same site conditions, labor rates, coal type, etc., as the new technology plant.

Table 2-1

REPRESENTATIVE EAST-CENTRAL COAL:
ILLINOIS NO. 6 BITUMINOUS

Proximate Analysis	Average	Range
Moisture	12.0	10 to 14
Volatile matter	33.0	31 to 35
Fixed carbon	39.0	37 to 41
Ash	16.0	13 to 19
Gross heating value, Btu/lb	10,100	9,800 to 10,400
Grindability, hardgrove	56.0	
Total sulfur, wt%	4.0	3.4 to 4.6
Ultimate Analysis wt%		
Moisture	12.0	10 to 14
Carbon	57.5	
Hydrogen	3.7	
Nitrogen	0.9	
Chlorine	0.1	
Sulfur	4.0	
Oxygen	5.8	
Ash	16.0	13 to 19
	100.0	
Sulfur Forms, wt%		
Pyritic	2.0	
Organic	1.9	
Sulfate	0.1	
	4.0	

Ash Fusion, °F	Reducing	Oxidizing
Initial deformation	1,950	2,250
Softening (H=W)	2,030	2,300
Hemispherical (H=1/2W)	-	-
Fluid	2,150	2,450

Ash Analysis, wt%	Average	Range
Silica, SiO_2	45.0	
Ferric oxide, Fe_2O_3	20.0	
Alumina, Al_2O_3	18.0	
Titanic oxide, TiO_2	1.0	
Calcium oxide, CaO	7.0	
Magnesia, MgO	1.0	
Sulfur trioxide, SO_3	3.5	
Potassium oxide, K_2O	1.9	
Sodium oxide, Na_2O	0.6	0.4 to 1.5
Phosphorous pentoxide, P_2O5	0.2	
Undetermined	1.8	
Total	100.0	

Table 2-2

REPRESENTATIVE WESTERN COAL:
WYOMING POWDER RIVER SUBBITUMINOUS

Proximate Analysis, wt%	Average	Range
Moisture	30.4	26 to 34
Volatile matter	31.1	29 to 34
Fixed carbon	32.1	29 to 44
Ash 6.4		
100.0		
Gross heating value, Btu/lb	8,020	7,400 to 8,300
Grindability, hardgrove	64	
Total sulfur, wt%	0.48	0.25 to 1.0

Ultimate Analysis, wt%		
Moisture	30.40	26 to 34
Carbon	47.85	46 to 50
Hydrogen	3.40	3 to 3.7
Nitrogen	0.62	0.5 to 0.8
Chlorine	0.03	0 to 0.1
Sulfur	0.48	0.25 to 1.0
Oxygen	10.82	9 to 12
Ash	6.40	4.4 to 11.7
	100.00	

Sulfur Forms, wt%	
Pyritic	0.11
Organic	0.33
Sulfate	0.04
	0.48

Ash Fusion, °F	Reducing	Oxidizing
Initial deformation	2,140	2,210
Softening (H = W)	2,195	2,255
Hemispherical (H = 1/2W)	2,230	2,290
Fluid	2,270	2,330

Ash Analysis, wt%	Average	Range
Silica, SiO_2	31.6	25 to 36
Ferric oxide, Fe_2O_3	4.6	2.7 to 5.5
Alumina, Al_2O_3	15.3	13 to 17
Titanic oxide, TiO_2	1.1	0.9 to 1.5
Calcium oxide, CaO	22.8	19 to 30
Magnesia, MgO	4.7	3.5 to 5.6
Sulfur trioxide, SO_3	16.6	12 to 21
Potassium oxide, K_2O	0.4	0.2 to 0.8
Sodium oxide, Na_2O	1.3	0.9 to 2.1
Phosporous pentoxide, P_2O_5	0.8	0.2 to 1.5
Undetermined	0.8	
Total	100.0	

Table 2-3

REPRESENTATIVE SOUTH-CENTRAL LIGNITE:
DARCO SEAM - EAST TEXAS

Proximate Analysis	Average	Range
Moisture	34.9	
Volatile matter	29.0	
Fixed carbon	25.3	
Ash 10.8		
100.0		
Gross heating value, Btu/lb	6,825	
Grindability, Hardgrove	50	
Total sulfur, wt%	0.7	0.6 to 1.0

Ultimate Analysis, wt%		
Moisture	34.90	
Carbon	39.70	
Hydrogen	2.90	
Nitrogen	0.70	
Chlorine	0.04	
Sulfur	0.70	0.6 to 1.0
Oxygen	10.30	
Ash 10.80		
100.00		

Sulfure Forms, wt%	
Pyritic	-
Organic	-
Sulfate	-
0.7	

Ash Fusion, °F	Reducing	Oxidizing
Initial deformation	1910	2040
Softening (H=W)	2130	2200
Hemispherical (H=1/2W)	2180	2240
Fluid	2190	2260

Ash Analysis, wt%	Average
Silica, SiO_2	42.50
Ferric oxide, Fe_2O_3	9.85
Alumina, Al_2O_3	21.00
Titanic oxide, TiO_2	1.16
Calcium oxide, CaO	10.90
Magnesia, MgO	2.89
Sulfur trioxide, SO_3	10.10
Potassium oxide, K_2O	0.29
Sodium oxide, Na_2O	0.04
Phosphorous pentoxide, P_2O_5	0.08
Undetermined	1.19
Total	100.00

Table 2-4

TYPICAL FUEL SPECIFICATIONS

FUEL ANALYSIS	Petroleum No. 2 Fuel Oil	Coal-Derived Fuels: Solid Boiler Fuel SRC-I	Coal-Derived Fuels: Liquid Boiler Fuel Heavy[a]	Coal-Derived Fuels: Liquid Boiler Fuel Distillate[b]	Coal-Derived Fuels: Turbine Fuel Distillate[c]	Intermediate-Btu Gas[d]
Nominal boiling range, °F	300 to 700	-	400+	350 to 700	325 to 700	-
Gravity, °API	32	-	-7.5	10.7	25.7	-
Viscosity, cSt, 100°F	2.6	-	500	3	2	-
Flash point, °F	150	-	150+	150+	150+	-
Proximate analysis, %						
Moisture (as-received)	-	2.21	-	-	-	-
Volatile matter	-	66.49	-	-	-	-
Fixed carbon	-	31.20	-	-	-	-
Ash	-	0.10	-	-	-	-
Total		100.00				
Ultimate Analysis, wt%						
Ash	-	0.10	200 ppm	0.03	-	-
Sulfur	0.1	0.68	0.48	0.23	0.01	-
Hydrogen	12.50	5.77	7.37	8.96	11.40	-
Carbon	87.38	84.29	88.15	86.26	88.46	-
Nitrogen	0.02	2.06	1.30	0.91	0.04	-
Oxygen	-	4.89	2.70	3.61	0.09	-
Moisture	-	2.21	-	-	-	
Total	100.00	100.00	100.00	100.00	100.00	
Heating Value, Btu/lb (as-received)	19,400	15,240	16,700	17,200	18,970	-
Ash Softening Temperature °F	-	1,990	-	-	-	-
Mole %						
CH_4	-	-	-		-	0.40
H_2	-	-	-	-	-	36.50
CO	-	-	-	-	-	50.90
CO_2	-	-	-	-	-	11.00
H_2S	-	-	-	-	-	0.15
COS	-	-	-	-	-	0.07
N_2	-	-	-	-	-	0.80
Ar	-	-	-	-	-	0.15
						100.00
Mole wt (Average)	-	-	-	-	-	20.3
Higher Heating Value Btu/SCF	-	-	-	-	-	287

---

[a] H-Coal® fuel oil, Ref: EPRI AF 710

[b] SRC-II distillate blend, Ref: R. Moshitto (P&M Co.), 13th Inter. Soc. Energy Conv. Conf., August 1978.

[c] Upgraded H-Coal® distillate (by hydrotreating), Ref: EPRI AF 710.

[d] Economics of Texaco gasification process for fuel gas production, FP-239, Task 18, Sept. 1980.

BEST DOCUMENT AVAILABLE

Table 2-5

REPRESENTATIVE WATER ANALYSIS
(MISSISSIPPI RIVER)

	mg/l	mg/l $CaCo_3$
Silica (SiO_2)	6.8	-
Calcium (Ca)	76	189
Magnesium (Mg)	16	66
Sodium (Na)	20	44
Potassium (K)	2.9	3.7
Bicarbonate (HCO_3)	246	202
Sulfate (SO_4)	56	58
Chloride (Cl)	26	37
Nitrate (NO_3)	6.9	5.6
Total dissolved solids	457	-
Total hardness	-	255

pH	8.0
Ionic strength, (meg/l)	9.2×10^{-3}
Temperature range, °F	40 - 80

Table 2-6

POWER PLANT EMISSION REGULATIONS (FEDERAL) - MARCH 1981

	WESTERN COAL (incl. lignite)		EASTERN COAL	
AIR	Present	Stringent (1)	Present	Stringent (1)
SO_2	90% to 70% (10)	95% removal	90% removal (10)	0.4 lb/MBtu (95%)
NO_x (13)	0.5 lb/MBtu	0.1-0.2 lb/MBtu (17)	0.6 lb/MBtu	0.1-0.2 lb/MBtu (17)
Particulate	0.03 lb/MBtu	0.02 lb/MBtu	0.03 lb/MBtu	0.02 lb/MBtu
Fine Part (<3 m)	N/R (2)	0.01 lb/MBtu	N/R (2)	0.01 lb/MBtu
Opacity	20%	5-10%	20%	5-10%
Control Device Emissions	N/R	(3)	N/R	(3)
Radioactive Material	N/R	Proposed by 1982 (14)	N/R	Proposed by 1982 (14)
Trace Metals	N/R	(11)	N/R	(11)
Trace Organics/POMs	N/R	(11)	N/R	(11)
Fugitive Dusts	N/R	(16)	N/R	(16)
WATER (4)				
Cooling Tower Blowdown				
pH	6-9	6-9	6-9	6-9
Chlorine	0.2 mg/l (12)	(12)	0.2 mg/l (12)	(12)
Trace Metals (5)	N/R		N/R	
Fly Ash Sluice Water				
pH	6-9	6-9	6-9	6-9
Suspended Solids	30 mg/l (7)	zero discharge	30 mg/l (7)	zero discharge
Oil and Grease	15 mg/l (7)	zero discharge	15 mg/l (7)	zero discharge
Others (6)				
SOLID WASTE				
Non-hazardous	inventory (18)	conc/discharge/recycle	same	same
Hazardous (15)	cradle to grave	conc/containment/recycle	same	same
NOISE				
In-plant (8)	90 dba	85 dba	90 dba	85 dba
Community (9)	65/55 dba	60/50 dba	65/55 dba	60/50 dba

FOOTNOTES:

(1) Standards were selected for study purposes to represent special local conditions such as PSD areas that may require very low emission rates.

(2) N/R = No current regulation.

(3) Regulations may be developed to control NH_3 and SO_3 emissions due to post-combustion NO_x control or flyash conditioning for ESP enhancement.

(4) Zero discharge of priority pollutants will be required for new plants in most of the U.S. Monitoring procedures will be stipulated by the appropriate regulations.

(5) Includes As, Se, Cd, Zn, Ni, Cu, Hg, Pb, Cr, Be, Ag, Ti, Sb, and corrosion inhibitors. Final effluent guidelines expected by mid 1981.

(6) Other discharge streams, such as bottom ash sluice water, boiler blowdown, cleaning waste water, and coal pile storage area runoff are individually regulated.

(7) Existing plants must conform to figure shown. New plants will be required to comply with zero discharge.

(8) OSHA Standard - 8 hour exposure.

(9) Day/Night at perimeter of the power plant.

(10) 90% reduction to a controlled emission rate of no more than 1.2 lb/10^6 Btu. 70% reduction for an uncontrolled emission rate less than 0.6 lb/10^6 Btu. 70 to 90% reduction for sources with uncontrolled emission rates of 0.6 to 6.0 lb/10^6Bu.

(11) No NSPS anticipated for trace metals or trace organics/POMs for 8-10 years. However, arsenic (inorganic) has been listed under NESHAP and EPA is considering cadmium and POM. Power plants, however, do not appear to be the principal targets for emission limitations of any of these pollutants.

(12) EPA BAT effluent guidelines recommend TRC not to exceed 0.14 mg/l (maximum) and no discharge of any of the 128 priority pollutants resulting from chemical additives.

(13) NO_x emissions standards are: 0.5 lb/MBtu for sub-bituminous coal and 0.6 lb/MBtu for bituminous coal.

(14) Radioactivity has been listed as a hazardous air pollutant under NESHAP. It is uncertain whether fossil fuel power plants will be required to control these emissions. Proposed rulemaking anticipated early 1982.

(15) High volume utility solid wastes (fly ash, bottom ash, scrubber sludge, and boiler slag) have been given a three-year exemtion from RCRA regulation while further tests are conducted. Other utility wastes, however, such as cleaning wastes, boiler and cooling tower blowdown, among others, may contain substances listed as, or determined to be, hazardous and thus subject to regulations.

(16) Fugitive emissions are regulated via the PSD regulations; these emissions consume the particulate increment and thus are controlled to the degree necessary.

(17) These values assume levels to be achieved through combustion modification. Postcombustion NO_x control requirements have the potential for further reduction. For study purposes, a value of 0.2 lb/10^6Btu should be used.

(18) Nonhazardous waste disposal facilities must comply with criteria to protect groundwater, surface water, endangered species, and food chain crops. 100-year flood plains must be avoided.

[redacted]

Chapter 3

COST-ESTIMATING PREMISES

3.1 INTRODUCTION

This chapter presents and discusses the definitions and methods for treating the economic variables that are a part of most cost estimates for new and existing power-generating technologies. EPRI is most concerned with comparing the relative economic advantages and disadvantages of new technologies rather than the absolute cost of a specific technology. Therefore, the main emphasis is on consistency in both the economic premises presented here and the design premises that were presented in Chapter 2. Since one set of premises cannot cover all possible situations, the Planning and Evaluation Division staff should be consulted in cases where special definitions are required.

3.2 COST ESTIMATE

The cost estimate includes both capital and operating costs along with fuel requirements and other consumables whose cost may vary with time. The cost estimate is generally computed as though the technology is in a "mature" state of development. Extra facilities that will be needed for demonstration or first commercial plants are not normally included in the cost estimates in the Technical Assessment Guide.

3.3 CAPITAL INVESTMENT BASIS

The capital cost components are shown in Table 3-1. The definitions for the capital cost components are presented in the following sections.

3.4 TOTAL PLANT COST

The total plant cost (TPC) is developed on the basis of instantaneous construction (also called overnight construction) and is expressed in December (of a reference year) dollars. The reference year to be used is given in Exhibit App B1-1 in Appendix B. The adjustments to express the total plant investment (TPI) at the plant in-service date or startup date are presented in Section 3.5.1.

The TPC is the sum of the following:

1. Process capital
2. General facilities capital
3. Engineering and home office fees
4. Project contingency
5. Process contingency

These items are discussed in the following sections. Table 3-2 gives a recommended format for the cost breakdown for the TPC.

3.4.1 Process Capital

Process capital is the total constructed cost of all on-site processing and generating units including all direct and indirect construction costs. All sales taxes must be included where applicable. As shown in Table 3-2, the process capital cost is to be divided into major plant sections (e.g., fuel storage, combustion systems, emission-control systems, generators). The specific section breakdown should be agreed upon with the EPRI project manager who is responsible for the study. In addition, the total process capital for each plant section should be broken down into factory materials, field materials, field labor, and indirect field costs.

3.4.2 General Facilities

The capital cost of the general facilities is to be given explicitly. The general facilities include roads, office buildings, shops, laboratories, etc., and are generally in the range of 5 to 20% of the process capital cost. Fuel, chemical, and by-product storage systems are to be included in the process capital costs and are not part of the general facilities. The cost basis for the general facilities will be established by the contractor with the concurrence of the EPRI project manager. Sales taxes must be included where applicable.

3.4.3 Engineering and Home Office Overhead Including Fee

An estimate is to be included of the engineering and home office overhead and fee that is considered representative of the type of plant in the study. These fees may be included in the process capital and general facility capital costs if the contractor's cost-estimating system incorporates estimates of these fees as a part of the equipment costs. The capital cost summary tables must indicate where these fees have been included. Ten to fifteen percent of the process capital is typical for these fees.

3.4.4 Contingencies

EPRI uses two types of contingencies: the project contingency and the process contingency. The project contingency is intended to cover the uncertainty in the cost estimate itself, whereas the process contingency covers the uncertainty in the technical performance of the equipment. In both cases the contingencies represent costs that are expected to occur.

3.4.4.1 Project Contingency. The project contingency is a capital cost contingency factor that covers the cost of additional equipment or other costs which would result from a more detailed design of a definitive project at an actual site. Table 3-3 presents guidelines for relating the project contingency to the level of design-estimating effort. Thus, by specifying the project contingency, the level of design-estimating effort can be defined, or vise versa. The contingency factors developed for each plant section should be shown explicitly.

3.4.4.2 Process Contingency. The process contingency is a capital cost contingency factor applied to a new technology in an effort to quantify the uncertainty in the technical performance and cost of the commercial-scale equipment. The following guidelines are provided to aid in assigning process contingency allowances to various sections of the plant.

State of Technology Development	Percentages of Installed Section Cost
New concept with limited data	40% and up
Concept with bench-scale data available	30 to 70%
Small pilot plant data (e.g., 1 MW) available	20 to 35%
A full-size module has been operated (e.g., 20-100 MW)	5 to 20%
The process is used commercially	0 to 10%

The process contingency should be given separately for each major plant section as shown in Table 3-2.

3.5 TOTAL CAPITAL REQUIREMENT

The total capital requirement (TCR) includes all capital necessary to complete the entire project. These items include:

1. The total plant investment (TPI) at the in-service date. TPI includes an allowance for funds used during construction (AFDC).
2. Prepaid royalties
3. Preproduction (or startup) costs
4. Inventory capital (fuel storage, etc.)
5. Initial chemicals and catalyst charges
6. Land

These items are discussed in the following sections.

3.5.1 Total Plant Investment at the In-Service Date (TPI)

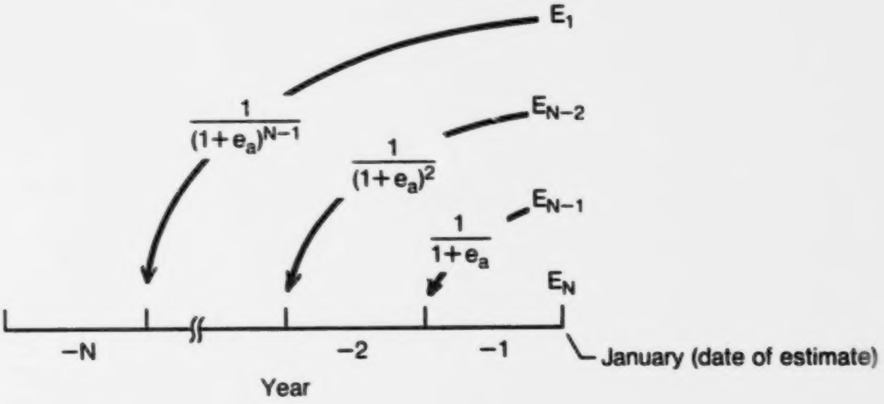
The TPI at the in-service date includes escalation of construction costs and AFDC (sometimes called interest during construction) over the construction period. TPI is computed from the TPC (where the TPC is expressed on an "overnight" or instantaneous construction basis) as follows:

From the plant design-construction expenditure schedule the amount of moneys spent during each year of construction is determined and referred to as E_j. For consistency, E_j is assumed to be spent at the end of the year. E_j is expressed in Dec (reference-year) dollars.

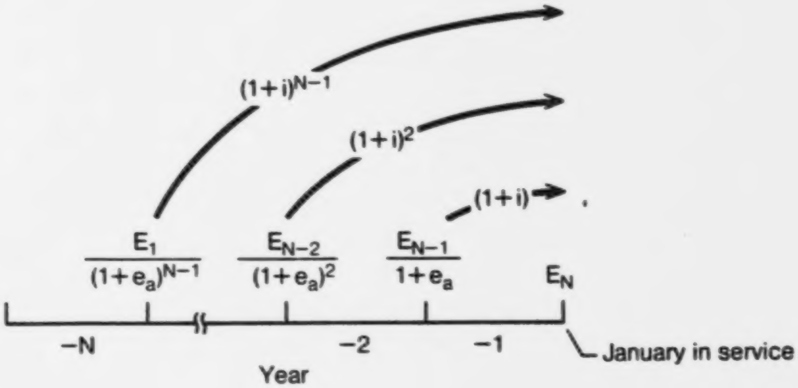
Therefore, $TPC = \sum_{j=1}^{N} E_j$

Where N is the total design/construction time in years.

To determine the actual money as spent over a construction period that ends in December (reference year), the costs are de-escalated back in time as shown below.


E_1
$\frac{1}{(1+e_a)^{N-1}}$
E_{N-2}
$\frac{1}{(1+e_a)^2}$
E_{N-1}
$\frac{1}{1+e_a}$
E_N
−N
−2
−1
January (date of estimate)
Year

Once the money is spent, interest charges are accumulated as part of the AFDC at an interest rate i that is equivalent to the weighted cost of capital. The accumulation of all costs at the reference year is shown in the following time diagram.


$(1+i)^{N-1}$
$(1+i)^2$
$(1+i)$
$\frac{E_1}{(1+e_a)^{N-1}}$
$\frac{E_{N-2}}{(1+e_a)^2}$
$\frac{E_{N-1}}{1+e_a}$
E_N
−N
−2
−1
January in service
Year

Hence, $\mathrm{TPI} = E_1 \left(\frac{1+i}{1+e_a}\right)^{N-1} + \ldots\ E_{N-1}\left(\frac{1+i}{1+e_a}\right) + E_N$

For the case where the construction expenditure rate is assumed to be uniform $E_1=E_2=E_j=\mathrm{TPC}/N$ the following can be derived:

TPI (Dec reference-year) = TPC (Dec reference-year dollars) x AF

Where $\mathrm{AF} = \frac{1}{N}\,(1 + Z + Z^2 + \ldots + Z^{N-1})$

$Z = (1+i)/(1+e_a)$

i = weighted cost of capital (interest cost for spent funds)

e_a = the apparent annual escalation rate for the plant equipment (generally e_a is assumed to be equal to the annual inflation rate, e_i, for capital equipment)

N = Design-construction period in years

TPC = Instantaneous total plant cost in December (reference-year) dollars

TPI = Total plant investment including AFDC at an annual interest rate of i and an annual escalation rate of e_a for a hypothetical December (reference-year) in-service. This is equivalent to an in-service date of January of the year following the reference year

Sample Calculation IV in Chapter B-5 gives an example of the above calculation. Idealized construction periods for several types of power plants are shown in the following table.

Idealized Time Required For Construction (N)	Example of Plant Type
6 years	Nuclear
5 years	Pulverized coal-fired (1000 MW unit)
4 years	Pulverized coal-fired (500 MW unit)
3 years	---
2 years	Oil-fired combined cycle (250 MW unit)
1 year	Combustion turbine (75 MW unit)

The periods shown in the above table are idealized in that no allowance is included for externally caused delays such as regulatory delays or labor strikes. Actual construction times may be somewhat longer. The construction times for new technologies should be estimated in a fashion that is consistent with the data in the above table.

The adjustment factor, AF, for converting TPC into TPI for plants with a uniform rate of capital expenditures is given in Section App B.4.8 in Appendix B. For consistency, a uniform expenditure rate should be assumed for new technologies unless an estimate of the actual expenditure rate is available.

3.5.2 Prepaid Royalties

Some new technologies may have royalty charges on portions of the plant. These royalty charges, if known, must be included here. For proprietary processes with an uncertain royalty, a value of 0.5% of the process capital is recommended.

3.5.3 Preproduction Costs

The preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. For EPRI purposes, the preproduction costs are estimated as follows:

1. One month fixed operating costs (operating and maintenance labor, administrative and support labor, and maintenance materials).
2. One month of variable operating costs (consumables) at full capacity excluding fuel (these variable operating costs include chemicals, water, and other consumables and waste disposal charges).
3. Twenty-five percent of full capacity fuel cost for one month (this charge covers inefficient operation that occurs during the startup period).
4. Two percent of total plant investment (TPI). This charge covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.

The method for computing the operating costs needed for the above preproduction cost estimate is given in Section 3.6.1.

3.5.4 Inventory Capital

The value of inventories of fuels, other consumables, and by-products is capitalized and included in the inventory capital account. The inventory capital is estimated as follows:

Type of Plant (See Section 2.2)	Nominal Capacity Factor	Fuel and Consumable Inventory Days at Full Load (100% Capacity)
Baseload	65%	60
Intermediate	30%	30
Peaking	10% (or less)	5

The prices for the fuel and consumables are given in Exhibits App B1-1 and App B2-1 through App B2-8 in Appendix B.

3.5.5 Initial Catalyst and Chemicals Charge

The initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital) is to be included.

3.5.6 Land

Although land costs are site-specific and variable, a nominal cost for land is to be included and is given in Exhibit App B1-1 of Appendix B.

3.6 OPERATING COSTS

The operating costs are to be estimated for a year of normal operation and presented in December (reference-year) dollars. The costs also will be computed on a 10-year and a 30-year levelized basis (see Chapter 1).

The operating costs are divided into fixed, variable, and consumable costs. The fixed costs are essentially independent of actual capacity factor, number of hours of operation, or the amount of energy produced and are generally expressed in $/kW-yr. The variable costs and consumables are directly proportional to the amount of energy produced and are referred to as incremental costs. They are generally expressed in mills/kWh.

All operating costs--fixed, variable and consumable--are subject to inflation.

3.6.1 Fixed and Variable Operating Costs

Fixed operating costs include the following:

1. Operating labor
2. Maintenance (may also have a significant variable component)
3. Overhead charges

These items are discussed in the following sections.

3.6.1.1 Operating Labor. An estimate is to be made of the number of operating jobs (OJ) that are required to operate the plant. The operating labor charges (OLC) are then computed using the average labor rate (ALR) as follows:

$$\text{OLC} = \frac{(\text{OJ}) \times (\text{ALR}) \times (8760 \text{ hr/yr})}{(\text{Net capacity of plant in kW})} = \$/\text{kW-yr}$$

The ALR includes payroll burden and is given in Exhibit App B1-1 in Appendix B.

3.6.1.2 Total Maintenance Costs. Annual maintenance costs for new technologies are often estimated as a percentage of the installed capital cost of the facilities. The percentage varies widely depending on the nature of the processing conditions and the type of design. Maintenance costs in the ranges shown below are representative.

Type of Processing Conditions	Maintenance Percentage of Replacement Process (or General Facility) Capital Cost/Yr[a]
Corrosive and abrasive slurries	6.0 to 10 (& higher)
Severe (solids, high pressure and temperature)	4.0 to 6 (& higher)
Clean (liquids and gases only)	2.0 to 4
General facilities and steam electrical systems	1.5 to 3.0

---

[a] Minimum capital cost plants will generally experience maintenance costs at the high end of the range.

The maintenance cost estimates will be developed by the contractor with concurrence of the EPRI project manager.

The maintenance cost estimates should be separately expressed as maintenance labor and maintenance materials. A maintenance labor materials ratio of 40/60 may be used for this breakdown if other information is not available.

3.6.1.3 Overhead Charges. The only overhead charge included in the power plant studies is a charge for administrative and support labor, which is taken as 30% of the operating and maintenance labor.

General and administrative expenses are not included.

3.6.2 Breakdown of Operating Costs into Fixed and Variable Components

From utility experience, baseloaded plants tend to have a relatively high fixed component of the operating cost, whereas peaking and intermediate plants have a relatively high variable component. To break the operating costs computed in Section 3.5.1 into fixed and variable components, it is assumed that the portion of the operating costs that are fixed is equal to the expected nominal capacity factor for the plant, which is given in Section 2.2 (65% base, 30% intermediate, and 10% peaking). The balance of the cost is assumed to be variable. An example of the calculation is shown below.

Example 3-1: Given a generating unit with a 65% capacity factor, and a total O&M (the sum of operating labor, total maintenance and overhead) of $24/kw-yr, determine the breakdown between fixed O&M and variable O&M costs.

$$\text{Fixed O\&M} = (0.65)(24) = 15.6 \ \$/\text{kW-yr}$$

$$\text{Variable O\&M} = \frac{(1 - 0.65)(24)\ \$/\text{kW-yr}\ (1000\ \text{mills}/\$)}{0.65\ \ (8760\ \text{hrs/yr})}$$

$$= 1.5\ \text{mills/kWh}$$

It is important to emphasize that all operating costs are subject to inflation and that "fixed" merely implies that the cost is not a function of the amount of energy generated.

3.6.3 Consumables

Consumables include water, chemicals, and other items whose consumption is directly proportional to the energy output. The cost to be used for these items is given in Exhibit App B1-1 of Appendix B.

3.6.4 By-Product Credits

By-product credits (if any) are based on values given in Exhibit App B1-1 of Appendix B.

3.6.5 Fuel Cost

Recommended fuel costs for coal types included in Chapter 2, Tables 2-1, 2-2, and 2-3 are given in Exhibit App B2-1 of Appendix B. Costs for other coals are also given in Appendix B.

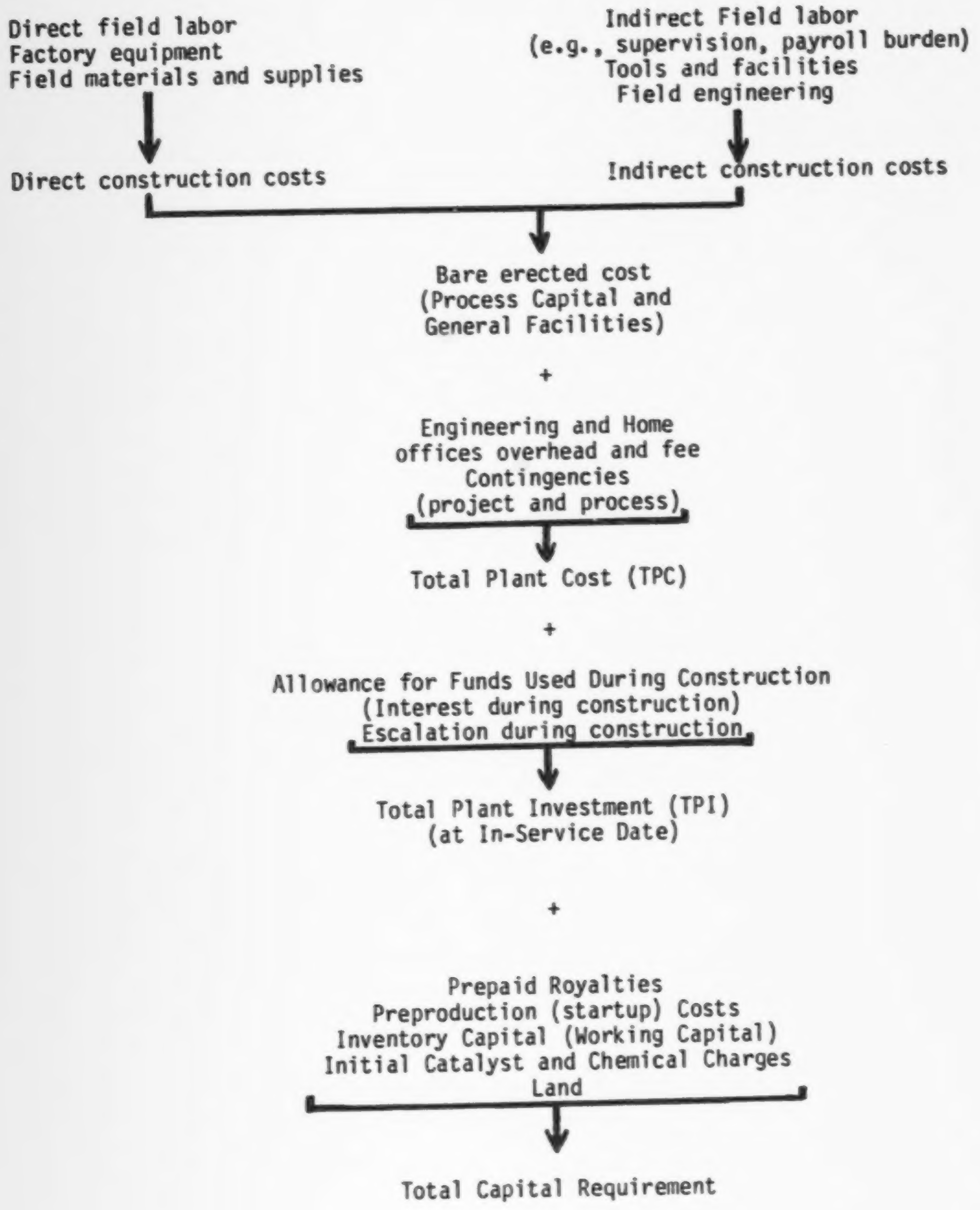
Petroleum-based fuel price projections are given in Exhibit App B2-8 in Appendix B.

Uranium price projections are given in Exhibit App B2-7 in Appendix B.

Synthetic fuel price information is given in Section App B3 of Appendix B.

Table 3-1

COMPONENTS OF CAPITAL COST



Direct field labor
Factory equipment
Field materials and supplies

Direct construction costs

Indirect Field labor
(e.g., supervision, payroll burden)
Tools and facilities
Field engineering

Indirect construction costs

Bare erected cost
(Process Capital and
General Facilities)

+

Engineering and Home
offices overhead and fee
Contingencies
(project and process)

Total Plant Cost (TPC)

+

Allowance for Funds Used During Construction
(Interest during construction)
Escalation during construction

Total Plant Investment (TPI)
(at In-Service Date)

+

Prepaid Royalties
Preproduction (startup) Costs
Inventory Capital (Working Capital)
Initial Catalyst and Chemical Charges
Land

Total Capital Requirement

Table 3-2

EXAMPLE FORMAT FOR TOTAL PLANT COST DETAIL
(December 19__ dollars)

Plant Section	Factory Materials	Field Materials	Field Labor	Indirect Field Costs	Sales Tax	Total	Engrg & Home Office Ov'hd & Fee	Contingencies Process	Contingencies Project	Total Plant Cost
Coal Storage										
Coal Handling										
Coal Combustion										
(etc.)										
Totals (Process Capital)						A				
General Facilities						B				
Totals							C	D	E	F

Example Total Plant Cost	Summary $/kW
Process Capital	A
General Facilities	B
Engrg & Home Office Ov'hd & Fee	C
Project Contingency	D
Process Contingency	E
Total Plant Cost	F

Table 3-3

DESIGN AND COST ESTIMATE CLASSIFICATIONS

Item	Design/ Estimate Description	Project Contingency Range	Design Information Required	Cost Estimate Basis Major Equipment	Cost Estimate Basis Other Materials	Labor
Class I	Simplified	30% to 50%	General site conditions, geographic location & plant layout. Process flow/operation diagram. Product ouput capacities	By overall project or section-by-section based on capacity/ cost graphs, ratio methods, and comparison with similar work completed by the contractor, with material adjusted to current cost indices and labor adjusted to site conditions.		
Class II	Preliminary	15% to 30%	As for Type Class I plus engineering specifics, e.g.: Major equipment specifications. Preliminary P&I flow diagrams.	Recent purchase costs (including freight) adjusted to current cost index.	By ratio to major equip. costs on plant parameters.	Labor/material ratios for similar work, adjusted for site conditions and using expected average labor rates.
Class III	Detailed	10% to 20%	Complete process design. Engineering design usually 20%-40$ complete. Project construction schedule. Contractural conditions and local labor conditions.	Firm quotations adjusted for possible price escalation with some critical items committed.	Firm unit cost quotes (or current billing costs) based on detailed quantity take-off.	Estimated man-hour units (including assessment) using expected labor rate for each job classification.
				Pertinent taxes & freight included.		
Class IV	Finalized	5% to 10%	As for Class III, with engineering essentially complete.	As for Class III, with most items committed.	As for Class III, with material on approximately 100% firm basis.	As for Class III, some actual field labor productivity may be available.

Chapter 4

AVAILABILITY ANALYSIS

4.1 INTRODUCTION

All generating units do not have the same availability or reliability, and these differences must be quantified in economic evaluations. Since historical data are unavailable for new technologies with no operating experience, forecasting availability data for new technologies depends largely on empirical methods such as analogy, engineering judgment, and rules of thumb. This forecasting produces estimates for comparative assessments but not in an absolute sense. The resulting availability data provided in Appendixes B and C of the white pages helps avoid the adoption of arbitrary estimates and helps keep studies comparable.

This chapter defines the necessary concepts and provides methods for incorporating these concepts into TAG procedures. These procedures allow generating unit availability to be included in production costing calculations, system reliability assessments such as loss of load probability (LOLP) calculations, screening and revenue requirement calculations, and alternative plant design tradeoffs. A supplementary report, Availability of Advanced Generating Technologies for the 1981 Technical Assessment Guide, EPRI Report PE-81-6-LD, May 1981, describes the TAG availability assumptions and analysis for each generating cycle and provides the complete results. This analysis uses CONFIG, a small computer program for unit configuration evaluation that is distributed by the EPRI Software Center (CONFIG Users Manual, EPRI Report PE-1769-CCM).

4.2 DEFINITIONS

The following parameters describe the TAG availability data presented in Appendixes B and C:

- Planned Outage Rate
- Unplanned Outage Rate
- Equivalent Unplanned Outage Rate

- Operating Availability
- Average Daily Unavailability
- Equivalent Availability
- Capability Ratio

These parameters are compatible with GADS* terminology as well as with requirements for availability data used in performing utility generation planning assessments. TAG availability definitions are presented in Exhibit 4-1. Planned outage rate, unplanned outage rate, equivalent unplanned outage rate, operating availability, and equivalent availability use GADS terminology, and average daily unavailability and capability ratio are additional availability parameters introduced in TAG.

There are several general differences between TAG and GADS definitions. First, TAG availability parameters are calculated with potential unit MW output states and associated probabilities determined as described in EPRI Report PE-81-6-LD. GADS availability data are developed directly from historical existing unit operating information.

Second, TAG availability definitions are determined using only two classes of outages--planned outages and unplanned outages. GADS availability definitions are determined using planned outages and four classes of unplanned outages, as listed in ANSI/IEEE Trial Use Standard #762.

Third, TAG outage rate definitions are based on unit availability--service hours plus economy outage hours. GADS outage rate definitions are based on service hours only.

Parameters used in developing the TAG availability definitions are described in Exhibit 4-2.

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*Generating Availability Data System of the North American Electric Reliability Council (NERC) (ANSI/IEEE Trial Use Standard #762).

Exhibit 4-1

TAG AVAILABILITY DEFINITIONS

Planned Outage Rate (POR)*

$$= \frac{\text{Planned Outage Hours}}{\text{Period Hours}}$$

Unplanned Outage Rate (UOR)*

$$= \frac{\text{Unplanned Outage Hours}}{\text{Period Hours - Planned Outage Hours}}$$

Equivalent Unplanned Outage Rate (EUOR)*

$$= \frac{\text{Unplanned Outage Hours + Equivalent Unplanned Derated Outage Hours}}{\text{Period Hours - Planned Outage Hours}}$$

Operating Availability (OA)*

$$= (1\text{-POR})(1\text{-UOR})$$

Average Daily Unavailability (ADU)*

$$= 1 - \frac{\text{EA}}{(1\text{-POR})(1\text{-UOR})}$$

Equivalent Availability (EA)*

$$= (1\text{-POR})(1\text{-EUOR})$$
$$= (1\text{-POR})(1\text{-ADU})(1\text{-UOR})$$

Capability Ratio (CR)*

$$= \frac{\text{Rated Unit Capacity}}{\text{Effective Load Carrying Capability @ Slope m = 1000}}$$

---

*Defined in Per-Unit

Exhibit 4-2

AVAILABILITY PARAMETER DESCRIPTION

Period Hours = The clock hours in the period under consideration, generally one year (8760 hours).

Planned Outage Hours = The time in hours during which a unit is removed from service for planned outages such as scheduled overhaul or inspection.

Unplanned Outage Hours = The time in hours during which a unit is unavailable due to occurrence of a component failure or condition which requires that the unit be removed from service.

Equivalent Unplanned Derated Outage Hours = The sum of the time in hours during which load on a unit must be reduced due to occurrence of a component failure multiplied by the corresponding per-unit capacity reduction.

Effective Load Carrying Capability @ Slope m = 1000 = Effective load carrying capability of a unit represents the additional load a unit added to a utility system can serve, maintaining the same loss of load probability (LOLP) as before the unit is added. Slope m = 1000 is a reference that represents a strong interconnected utility system which allows the installation of large units (1000 to 1200 MW) to the system. See L. L. Garver, "Effective Load Carrying Capability of Generating Units," IEEE Transaction on Power Apparatus and Systems, PAS-85, August 1966, pp. 910-919.

BEST DOCUMENT AVAILABLE

4.3 EVALUATIONS

Availability data for the technologies presented in Appendixes B and C are used to perform analyses which include:

- Detailed Reliability and Revenue Requirement Studies
- Simplified Screening and Revenue Requirement Studies
- Alternative Design Trade-offs

4.3.1 Detailed Reliability and Revenue Requirement Studies

Generation planning studies of both conventional and advanced generation technologies consist primarily of utility system reliability assessments and revenue requirement analyses. In these studies the relative system reliability and total production cost of alternative generation expansion plans are analyzed and the relative revenue requirements are compared, maintaining appropriate system reliability. Probabilistic generation system reliability assessments, such as LOLP, and probabilistic production costing calculations are commonly used in generation planning studies. These assessments require appropriate modeling of individual unit availability data including both planned and unplanned outage rates.

The most common availability model used for these assessments is the classical two-staged availability model with the unit either in-service or out-of-service. This model is accurate for all subsystems connected in series. However, many generating technologies consist of subsystems connected in parallel, and many units are often required to operate at reduced capacity. Consideration of these factors requires either a multiple-state availability model or an equivalent two-state (classical) availablility model.

The availability data for the advanced technologies contained in Appendixes B and C consist of two equivalent two-state availability models, which consider the impact of partial outages on unit availability. The two alternative models, EUOR and ADU, are compatible with the input data requirements of most LOLP and probabilistic production costing programs in use today. The EUOR availability model uses the equivalent unit unplanned outage rate (EUOR) and rated unit capacity while the ADU availability model uses the full unit unplanned outage rate (UOR) and (1 - ADU) unit capacity. Both availability models allow consideration of partial outages in generation planning assessments. Estimates of the uncertainty in EUOR for the advanced technologies are presented in Appendix C. These data were calculated using high and low estimates for the two or three component outage rates that contribute most to overall outage rate uncertainty.

4.3.2 Simplified Screening and Revenue Requirement Studies

Appendix B data also include the ratio of rated capacity to effective load carrying capability for all the advanced technologies.

The effective load carrying capability of a generating unit represents the additional load that a utility can serve at the same loss of load probability (LOLP) as before the unit was added to its system. Differences in effective load carrying capabilities between units, a measure of relative unit availability, should be recognized in determining the relative capital cost of alternative capacity additions to determine relative revenue requirements. These adjusted costs permit economic comparisons between alternatives having different availabilities in simplified economic analyses. To approximate these adjusted costs, the carrying charges and fixed operating and maintenance costs of each alternative may be multiplied by its ratio of full capacity to effective capability. This correction presumes (1) no maintenance occurs during the customer's peak load season, (2) no other factors contribute to the utility's LOLP, and (3) each generating unit carries its own contribution to the utility's reserve capacity requirement for system reliability purposes. This last presumption overstates penalties due to unavailablity differences if some of the reserve capacity is composed of low capital cost peaking technology such as combustion turbine. This approach is an option availability in the economic screening computer program COMPLETE discussed in Chapter 6.

4.3.3 Alternative Design Trade-offs

Using the concepts of effective load carrying capability and resulting effective cost, generating unit design modifications can be assessed. Oversizing, sparing, and upgrading of equipment can be compared to optimize a design. Economy of scale and reliability of scale data are two equipment characteristics that are required to accomplish trade-off analyses. This approach can even be extended, given rates of improvement, into the analysis of optimum unit size and the planning of unit scale up during the development process of new technologies, although such extension is beyond the scope of the current Technical Assessment Guide.

Chapter 5

TREATMENT OF UNCERTAINTY

5.1 INTRODUCTION

Previous chapters discussed EPRI cost and performance premises. Data estimates for each technology are presented in Appendix B (white pages). This chapter extends these data to include estimates of uncertainty on the following variables.

- Total capital requirement
- Commercial service date
- Unplanned outage rate

Also presented are underlying assumptions, sources of uncertainty, and interpretations necessary in the use of these data.

5.2 DATA ASSUMPTIONS

Appendix C of the white pages provides the estimates of uncertainty for the selected variables. For the total capital requirements, all users' costs are included, e.g., AFDC, land, preproduction and inventory costs. The data are directly usable for economic calculations.

The estimates correspond to particular plant design, optimized for minimum cost of electricity over the book life, including the effects of generating unit availability. While higher availability may be engineered into a design, the capital costs would be increased and overall plant economics would change. Thus, the uncertainty in the plant capital costs does not cover all values that would be possible through variation of the plant design. Fixing the plant design allows the assumption that capital cost and the unplanned outage rate are probabilistically independent.

Capital cost and commercial service dates are not directly related. The capital costs are estimates for mature equipment. A mature state of development may not be achieved until several successive design and construction cycles have occurred, a period of up to several decades in some cases. The commercial service year does not relate to this mature state of development, but only to the end of the initial technology development and commercial demonstration process. Furthermore, the commercial service year does not presume that a technology is economic, or would or could actually be purchased.

The variables chosen to be encoded with probability distributions are those which contribute most to the uncertainty in the busbar cost of electricity. Not addressed are variables whose range of uncertainty would have a less pronounced impact on utility expansion decisions.

In Appendix C, three values are given for each variable. A 25% likelihood of occurrence is associated with the low estimate, 25% with the high estimates, and the remaining 50% change with the central estimate. The central estimate in Appendix C is not the same value as the single point estimate included in Appendix B. Appendix C results from subjective distributions estimated by EPRI staff. Data in Appendix B are derived from contractor cost and design studies adjusted for consistency and current EPRI premises. The degree of design optimism perceived by the EPRI staff dominates the remaining distinctions between these data.

The uncertainty data are intended for probabilistic analysis. An example of such analysis is provided in Chapter B-4. It indicates how a decision may be reversed when uncertainty is included in a comparison of two alternative generating technologies. In the example, it is assumed that the decision maker bases the choice on the expected value of outcomes. The example could be extended to account for the risk attitudes of regulated utilities.

5.3 SOURCES OF UNCERTAINTY

Many factors contribute to the uncertainty in estimates of capital costs, commercial service date, and unplanned outage rates. While by no means complete, four generic sets of factors are identified below.

1. Technical -- these include the effects of translating general plant performance specifications into detailed engineering designs
2. Estimation errors -- errors due to incomplete estimation
3. Economic -- these include the effects of changes in projected prices of materials, labor, and land

4. Other -- weather conditions, unanticipated regulations and political events drastically change the commercialization time table and costs

5.4 INTERPRETATION AND USE OF DATA

The data in Appendix C represent subjective opinions of EPRI staff. The fact that they are conditional distributions restricts their use. Strictly speaking, the probabilities are valid only if the factors held constant actually equal their nominal values.

To expand the scope of the variables considered would require convolution. Convolution refers to the mathematical operation of combining two or more random variables. For instance, one could convolve the current distributions on total capital requirements with the distribution on the cost of additional equipment.

Similarly, convolution could be used to obtain the probability on the first commercial order data recognizing the uncertainty in the construction duration and licensing requirements. However, if estimates of changes in costs or construction years are considered to be certain, they could simply be added to or subtracted from the corresponding values for each affected variable.

To revise the data as new information becomes available requires a different procedure. The procedure uses Bayes rule. The procedure is also used for calculating joint probabilities. For instance, it was assumed that the prices of materials were fixed. To calculate the probability that the capital costs are as shown in Appendix C and that the prices of materials are at their high value, one must multiply the probabilities in Appendix C by the probability that the prices of materials are at the high values. Other joint probabilities are calculated in a similar fashion. However, one should not assume that the probabilities on capital cost are valid if other factors held constant resolve themselves at other than the assumed values. Doing so would imply that the capital costs are independent of these factors.

Chapter 6

SYSTEM ANALYSIS

6.1 INTRODUCTION

Evaluation of new technologies at EPRI is based on electric utility planning methods that are applied within constraints imposed by the economy and the environment. The general objective embodied in these methods is minimization of revenue requirements for a utility system as a whole. Thus a new technology cannot be evaluated in isolation but only in the context of existing and future levels of generation supply and system load together with other new technologies that are allowed equal development opportunities.

Several EPRI programs and ongoing projects useful in R&D evaluation are described in this chapter. It is divided into three parts covering (1) the EPRI regional systems, (2) electric supply planning models, and (3) analysis of power and energy losses.

6.2 EPRI REGIONAL SYSTEMS

The EPRI Regional Systems provide a standard, neutral power system environment for the evaluation of new technologies, planning tools, and assessment methodologies. They consist of generation supply and system load information for the six regions of the United States shown in Exhibit 6.3. These 1990 reference systems can be used as starting points for the development of generation expansion scenarios.

The EPRI Regional Systems have evolved from the "Synthetic Utility Systems" published in EPRI Report EM-285. As did the Synthetic Utility Systems, the new EPRI Regional Systems allow evaluation of new technologies and generation system analysis methods and models on a consistent basis. The EPRI Regional Systems incorporate important changes in generation system trends since the Synthetic Utility Systems were developed in 1976 using 1975 data. Also, the new systems provide the following added capabilities:

- Regional assessment of EPRI R&D benefits
- More accurate and credible nationwide benefits assessment based on aggregation of regional results
- Analysis of regional concerns and issues pertinent to EPRI's R&D planning and strategy

The new regional systems supersede only the generation supply and system load information in the Synthetic Utility Systems. Transmission and distribution system information developed for the Synthetic Utility Systems (EM-285) will continue to be used.

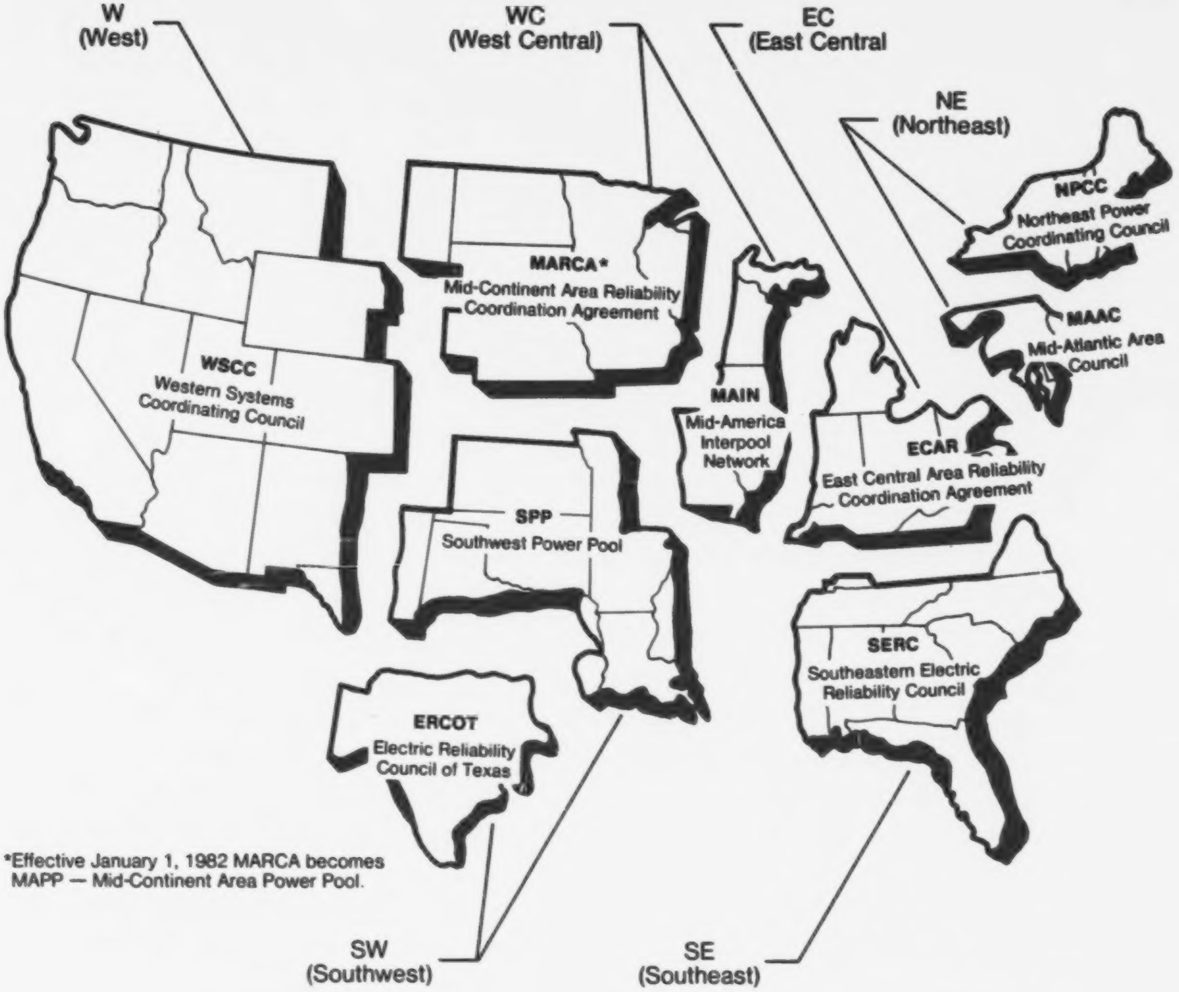
The data for existing generation supply in the EPRI Regional Systems complement the data for future generation supply technologies found in the TAG.

The EPRI Regional Systems data base, developed and managed by EPRI's Planning and Evaluation Division, is available on computer tape through the Electric Power Software Center. Instructions on how to access this information are published in EPRI Report P-1950-SR.

6.3 ELECTRIC SUPPLY PLANNING METHODS

EPRI has or is developing a number of programs for generation planning that include simple technology screening analyses, utility specific expansion packages, and regional and national equilibrium models. These methods are intended for successive and iterative use, depending on the scope of a particular study.

Central to utility planning methods is the concept of economic dispatch. Dispatching is the assignment of generating units or load control activities as customer demands change during the day so as to minimize total system operating costs. The usage that a device experiences (capacity factor) depends in part either on its variable operating cost compared to that of other devices. Other considerations that constrain capacity factor include transmission limitations, the minimum load level of a unit, and its ability to follow load changes. Load management, some hydro, and energy storage are dispatched by avoided costs. It is invalid to compare two technologies at the same capacity factor if economic dispatch would cause them to experience different levels of usage. Simulation of the utility system with each alternative is necessary to determine which option contributes the least to total revenue requirements of the whole utility system.


W
(West)
WC
(West Central)
EC
(East Central
NE
(Northeast)
NPCC
Northeast Power Coordinating Council
MAAC
Mid-Atlantic Area Council
MARCA*
Mid-Continent Area Reliability Coordination Agreement
WSCC
Western Systems Coordinating Council
MAIN
Mid-America Interpool Network
ECAR
East Central Area Reliability Coordination Agreement
SPP
Southwest Power Pool
SERC
Southeastern Electric Reliability Council
ERCOT
Electric Reliability Council of Texas
SW
(Southwest)
SE
(Southeast)

*Effective January 1, 1982 MARCA becomes MAPP — Mid-Continent Area Power Pool.

Exhibit 6-1. EPRI regional systems

Total revenue requirements include both the operating costs of all units together with the capital requirements of new additions. To reduce the level of effort for system analyses, screening techniques have been developed.

The screening analysis compares supply alternatives in order to identify those likely to be chosen to expand a utility system. It narrows the number of candidates, or conversely, it identifies the improvements necessary for a new alternative to compete economically. COMPETE is a program that produces screening curves through time as shown in Exhibit 6-2. In this instance, if it were necessary to limit the types of generation in a more detailed study, the Unit A and Unit C types could be left out. At no point do they represent the lowest cost alternatives. Since no exisiting generating units or customers' load data are used in a screening analysis, the procedure can only determine which options are economically viable. COMPETE is available from the EPRI Electric Power Software Center for distribution on time sharing computer services or by magnetic tape. (EPRI Report PE-2081-CCM)

Generation expansion packages add new electric supply and demand facilities to a specific set of utility data. The Over-Under Capacity Model seeks to determine an optimum generation reserve level, given the costs of service interruptions and the uncertainties in future electric demand. See EPRI Report EA-927, Costs and Benefits of Over/Under Capacity in Electric Power System Planning. The program is available from the EPRI Electric Power Software Center.

The Modular Generation Expansion Program (EGEAS) provides a common framework for future software developments. EGEAS is able to perform generation optimation, system reliability calculations, and production costing and provides a useful interaction with planning for transmission facilities. Contact the EPRI Power Systems Department for information on EGEAS.

Regional and national equilibrium models bring together energy and the economy. These models help assess the constraints within which electric systems develop. The models include estimates of fuel resources and of demands for basic services such as those resulting from productivity and population. ETA-Macro is one of several programs used in preparing the EPRI Overview and Strategy. Contact the EPRI Planning and Evaluation Division for information on ETA-Macro. The Integrated Forecasting Model (IFM) is an equilibrium model being prepared for R&D assessment that types of energy services. Contact the EPRI Energy Analysis Department for information on IFM.

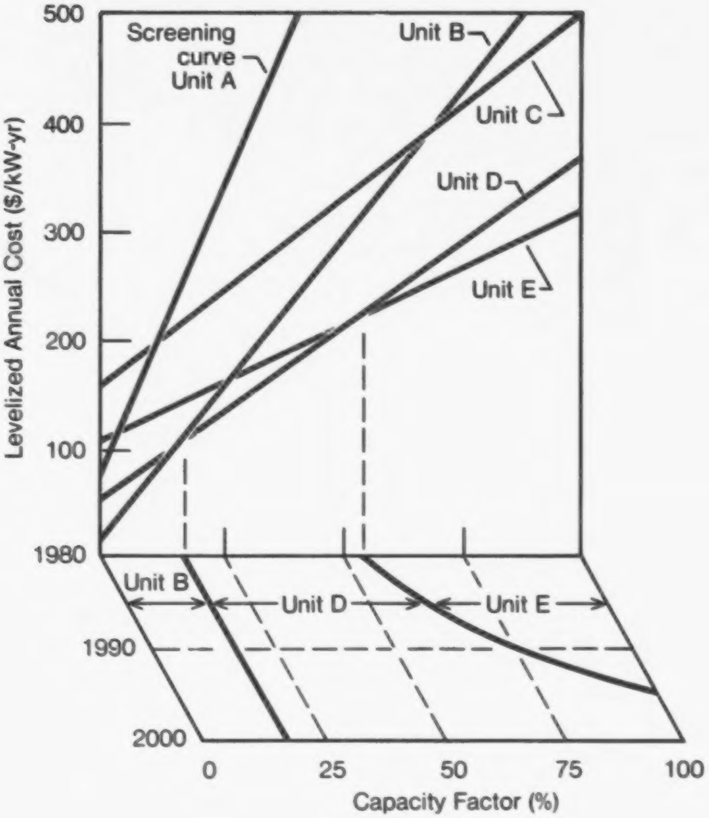


Exhibit 6-2. Example of screening analysis

In summary, the screening program concentrates attention on economic alternatives, the expansion programs identify the likely market share of unit each type, and the equililbrium models provide feedback to keep generation plans within their constraints.

6.4 ANALYSIS OF ELECTRICAL LOSSES

The final topic in this chapter deals with the transportation of electricity from the supply system to the customer.

The cost of electrical losses on a power system has two components--a capacity loss component and an energy loss component.

The capacity loss component is established from a determination of the magnitude of the losses at peak load. The energy loss component is established from a determination of the average loss over a period of time. These two components of the total cost are evaluated separately and added; the totals for various alternatives can then be compared to establish the incremental economic effect of the differences in losses.

Energy losses can either be essentially constant (such as transformer core losses) or can vary as the square of the electrical current (such as transformer copper losses).

The capacity loss component is evaluated from the peak load loss. For R&D evaluation purposes, it will be assumed that a change in losses will not affect the timing of new facilities but may affect the size. On this basis, the capacity component of losses would be evaluated at the incremental cost of increasing the size of new facilities. For EPRI purposes this is assumed to be two-thirds of the average cost of the facility. For generating facilities, with an assumed reserve margin of 20%, one kilowatt of incremental loss would be evaluated for EPRI purposes at 2/3 times 1.2, or 80% of the cost per kilowatt of new generating capacity. For other types of facilities one kilowatt of incremental loss would be evaluated at two-thirds the cost required to supply a kilowatt of new load. Such an evaluation should be considered a maximum for this component of a loss evaluation. The reader is reminded that the losses to any location in the system may affect all system facilities out to that point.

The energy loss component is evaluated from the peak load loss and the load factor for the facility involved. To calculate the average loss, the loss factor is used. The loss factor is defined as the ratio of the average loss to the loss at peak load. This factor depends on the shape of the load curve, but the following relationship has been found to represent a good approximation for a wide variety of reasonable load shapes:

$$\text{Loss factor} = 0.3\,(\text{load factor}) + 0.7\,(\text{load factor})^2 \text{ or}$$
$$\text{Loss factor} = (\text{load factor})^{1.6}$$

The national average load factor in 1980 was about 61.3%, and load factors for the nine NERC regions varied from 54% to 67%. Load factors for class of service varies from as little as 20% for the residential class to over 80% for some industrial customers. Projections reported by the North American Electric Reliability Council suggest a national average load factor of 63.2% in 1986. A 61.3% load factor implies a loss factor of 44.7%.

The energy loss component should be evaluated at the average incremental cost of generation. This is essentially fuel cost, but often these data are not available. The average incremental cost of generation is close to the average cost of fuel per kilowatt hour of generator output; therefore, for EPRI purposes, the average cost of fuel per kilowatt hour may be used as a reasonable approximation for loss calculations if the needed data are not available.

In summary, the procedure for EPRI purposes for evaluating electrical losses is as follows:

1. Determine power loss at peak load
2. Evaluate capacity component of losses at 0.8 times the cost per kilowatt of new generating capacity and 2/3 times the cost per kilowatt of new transmission and distribution capacity as applicable
3. Use an annual load factor and a calculated loss factor to determine annual energy losses as: power loss x loss factor x 8760
4. Evaluate energy component of losses at average incremental cost of generation

FOR ACTUAL PROBLEMS

APPENDIX A

ECONOMIC PARAMETERS

- FINANCIAL FACTORS

Type of Security	% of Total	Current Dollars Cost	Current Dollars Return	Constant Dollars Cost	Constant Dollars Return
Debt	50	11.0%	5.5%	2.3%	1.1
Preferred Stock	15	11.5	1.7%	2.8%	0.4
Common Stock	35	15.3	5.3%	6.3%	2.2
Total Annual Return (Discount Rate)			12.5%		3.7%

Inflation Rate	8.5%
Federal and State Income Tax Rate	50.0%
Investment Tax Credit	10.0%

- TAX AND BOOK LIFE(1)

Plant Class(2)	Tax Recovery(3)	Book Life
Nuclear Fueled Generation	10 years	30 years
Fossil-Fueled Generation Transmission & Distribution	15 years	30 years
Hydro Generation	15 years	60 years

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(1) See Section B-2.4.3 for more details

(2) Electric utility tax accountants generally agree that, until appropriate tax rules are promulgated, a 10-year tax life should be used for emerging technologies involving renewable resources.

(3) Based on the federal tax laws in effect on December 31,1981

- USE OF TABLES(1)

	Current Dollars	Constant Dollars
Present worth and levelizing calculations using the factors v^n and a_n	Table I	Table IV
Levelizing calculations using the L_n factor	II	V
Carrying charge factors for several classes of electric utility plant with and without tax preferences(2)	III	VI

(1) The user is cautioned that the use of an inflation rate other than 8.5% requires the calculation of a new discount rate as explained in Section B-2.7.

(2) Property tax and insurance totaling 2% is included in Tables III and VI.

Table I

Current Dollars
(i = 12.5%)

For present worth and levelizing calculations if an 8.5% inflation rate is used.

f Year	v^f	a_f	f Year	v^f	a_f
1	.8889	0.889	31	.0260	7.792
2	.7901	1.679	32	.0231	7.815
3	.7023	2.381	33	.0205	7.836
4	.6243	3.006	34	.0182	7.854
5	.5549	3.561	35	.0162	7.870
6	.4933	4.054	36	.0144	7.885
7	.4385	4.492	37	.0128	7.898
8	.3897	4.882	38	.0114	7.909
9	.3464	5.228	39	.0101	7.919
10	.3079	5.536	40	.0090	7.928
11	.2737	5.810	41	.0080	7.936
12	.2433	6.053	42	.0071	7.943
13	.2163	6.270	43	.0063	7.950
14	.1923	6.462	44	.0056	7.955
15	.1709	6.633	45	.0050	7.960
16	.1519	6.785	46	.0044	7.965
17	.1350	6.920	47	.0039	7.968
18	.1200	7.040	48	.0035	7.972
19	.1067	7.147	49	.0031	7.975
20	.0948	7.241	50	.0028	7.978
21	.0843	7.326	51	.0025	7.980
22	.0749	7.401	52	.0022	7.983
23	.0666	7.467	53	.0019	7.984
24	.0592	7.526	54	.0017	7.986
25	.0526	7.579	55	.0015	7.988
26	.0468	7.626	56	.0014	7.989
27	.0416	7.667	57	.0012	7.990
28	.0370	7.704	58	.0011	7.991
29	.0329	7.737	59	.0010	7.992
30	.0292	7.766	60	.0009	7.993

Current Dollars

($i = 12.5\%$)

Table II

Levelizing factor $\underline{L_n}$ based on an 8.5% annual inflation rate and an annual real escalation rate $\underline{e_r}$ as indicated.

$\%e_r$	L_{10}	L_{20}	L_{30}
0.0	1.488	1.930	2.314
0.2	1.504	1.966	2.374
0.4	1.519	2.003	2.437
0.6	1.535	2.042	2.502
0.8	1.552	2.081	2.569
1.0	1.568	2.121	2.638
1.2	1.584	2.162	2.710
1.4	1.601	2.203	2.785
1.6	1.618	2.246	2.863
1.8	1.635	2.290	2.943
2.0	1.652	2.335	3.026
2.2	1.670	2.382	3.112
2.4	1.687	2.429	3.202
2.6	1.705	2.477	3.294
2.8	1.723	2.527	3.391
3.0	1.742	2.578	3.490
4.0	1.836	2.851	4.049
5.0	1.937	3.160	4.723

[redacted]

Table III_N

Current Dollars

(i = 12.5%)

Book Life (n) 30 Years
Tax Recovery (m) 10 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.223	0.198	0.223
2	0.211	0.365	0.217
3	0.190	0.498	0.209
4	0.172	0.606	0.202
5	0.156	0.692	0.194
6	0.141	0.762	0.188
7	0.129	0.819	0.182
8	0.119	0.865	0.177
9	0.110	0.903	0.173
10	0.104	0.935	0.169
11	0.099	0.962	0.166
12	0.096	0.985	0.163
13	0.094	1.006	0.160
14	0.091	1.023	0.158
15	0.088	1.038	0.157
16	0.086	1.051	0.155
17	0.083	1.063	0.154
18	0.081	1.072	0.152
19	0.078	1.081	0.151
20	0.075	1.088	0.150
21	0.073	1.094	0.149
22	0.070	1.099	0.149
23	0.068	1.104	0.148
24	0.065	1.107	0.147
25	0.062	1.111	0.147
26	0.060	1.114	0.146
27	0.057	1.116	0.146
28	0.055	1.118	0.145
29	0.052	1.120	0.145
30	0.049	1.121	0.144

Table III_F

Current Dollars
($i = 12.5\%$)

Book Life (n) 30 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.223	0.198	0.223
2	0.214	0.367	0.219
3	0.199	0.507	0.213
4	0.185	0.622	0.207
5	0.171	0.718	0.202
6	0.159	0.796	0.196
7	0.148	0.861	0.192
8	0.137	0.914	0.187
9	0.128	0.958	0.183
10	0.119	0.995	0.180
11	0.112	1.026	0.177
12	0.105	1.051	0.174
13	0.100	1.073	0.171
14	0.094	1.091	0.169
15	0.089	1.106	0.167
16	0.086	1.119	0.165
17	0.083	1.130	0.163
18	0.081	1.140	0.162
19	0.078	1.148	0.161
20	0.075	1.156	0.160
21	0.073	1.162	0.159
22	0.070	1.167	0.158
23	0.068	1.171	0.157
24	0.065	1.175	0.156
25	0.062	1.179	0.156
26	0.060	1.181	0.155
27	0.057	1.184	0.154
28	0.055	1.186	0.154
29	0.052	1.187	0.153
30	0.049	1.189	0.153

[redacted]

Table III_H

Current Dollars
($i = 12.5\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.210	0.186	0.210
2	0.202	0.346	0.206
3	0.188	0.478	0.201
4	0.175	0.588	0.195
5	0.163	0.678	0.190
6	0.152	0.753	0.186
7	0.142	0.816	0.182
8	0.133	0.867	0.178
9	0.125	0.911	0.174
10	0.118	0.947	0.171
11	0.111	0.977	0.168
12	0.106	1.003	0.166
13	0.102	1.025	0.164
14	0.098	1.044	0.162
15	0.094	1.060	0.160
16	0.092	1.074	0.158
17	0.091	1.086	0.157
18	0.090	1.097	0.156
19	0.088	1.107	0.155
20	0.087	1.115	0.154
21	0.086	1.122	0.153
22	0.084	1.128	0.152
23	0.083	1.134	0.152
24	0.082	1.139	0.151
25	0.080	1.143	0.151
26	0.079	1.147	0.150
27	0.078	1.150	0.150
28	0.076	1.153	0.150
29	0.075	1.155	0.149
30	0.074	1.157	0.149

Table III_H

Current Dollars
($i = 12.5\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

t Year	Year by Year Carrying Charge (CC_t)	Cumulative Present Value of Carrying Charge ($V_{t,m,n}$)	Levelized Carrying Charge ($P_{t,m,n}$)
31	0.073	1.159	0.149
32	0.071	1.161	0.149
33	0.070	1.162	0.148
34	0.069	1.164	0.148
35	0.067	1.165	0.148
36	0.066	1.166	0.148
37	0.065	1.166	0.148
38	0.063	1.167	0.148
39	0.062	1.168	0.147
40	0.061	1.168	0.147
41	0.059	1.169	0.147
42	0.058	1.169	0.147
43	0.057	1.170	0.147
44	0.056	1.170	0.147
45	0.054	1.170	0.147
46	0.053	1.170	0.147
47	0.052	1.171	0.147
48	0.050	1.171	0.147
49	0.049	1.171	0.147
50	0.048	1.171	0.147
51	0.046	1.171	0.147
52	0.045	1.171	0.147
53	0.044	1.171	0.147
54	0.042	1.171	0.147
55	0.041	1.172	0.147
56	0.040	1.172	0.147
57	0.039	1.172	0.147
58	0.037	1.172	0.147
59	0.036	1.172	0.147
60	0.035	1.172	0.147

Table III_{NO}

Current Dollars
(i = 12.5%)

Book Life (n) 30 Years
Tax Recovery (m) 30 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge $(V_{f,m,n})$	Levelized Carrying Charge $(P_{f,m,n})$
1	0.249	0.222	0.249
2	0.243	0.413	0.246
3	0.236	0.579	0.243
4	0.230	0.723	0.240
5	0.223	0.847	0.238
6	0.217	0.954	0.235
7	0.210	1.046	0.233
8	0.204	1.125	0.230
9	0.197	1.193	0.228
10	0.191	1.252	0.226
11	0.184	1.302	0.224
12	0.177	1.346	0.222
13	0.171	1.383	0.221
14	0.164	1.414	0.219
15	0.158	1.441	0.217
16	0.151	1.464	0.216
17	0.145	1.484	0.214
18	0.138	1.500	0.213
19	0.132	1.514	0.212
20	0.125	1.526	0.211
21	0.119	1.536	0.210
22	0.112	1.545	0.209
23	0.106	1.552	0.208
24	0.099	1.557	0.207
25	0.093	1.562	0.206
26	0.086	1.566	0.205
27	0.079	1.570	0.205
28	0.073	1.572	0.204
29	0.066	1.575	0.204
30	0.060	1.576	0.203

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Table III_{HO}

Current Dollars

($i = 12.5\%$)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.233	0.207	0.233
2	0.229	0.388	0.231
3	0.226	0.547	0.230
4	0.223	0.686	0.228
5	0.220	0.808	0.227
6	0.216	0.915	0.226
7	0.213	1.008	0.224
8	0.210	1.090	0.223
9	0.207	1.161	0.222
10	0.203	1.224	0.221
11	0.200	1.279	0.220
12	0.197	1.327	0.219
13	0.193	1.368	0.218
14	0.190	1.405	0.217
15	0.187	1.437	0.217
16	0.184	1.465	0.216
17	0.180	1.489	0.215
18	0.177	1.510	0.215
19	0.174	1.529	0.214
20	0.171	1.545	0.213
21	0.167	1.559	0.213
22	0.164	1.572	0.212
23	0.161	1.582	0.212
24	0.158	1.592	0.211
25	0.154	1.600	0.211
26	0.151	1.607	0.211
27	0.148	1.613	0.210
28	0.144	1.618	0.210
29	0.141	1.623	0.210
30	0.138	1.627	0.209

Table III_{HO}

Current Dollars
($i = 12.5\%$)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f, m, n}$)	Levelized Carrying Charge ($P_{f, m, n}$)
31	0.135	1.630	0.209
32	0.131	1.633	0.209
33	0.128	1.636	0.209
34	0.125	1.638	0.209
35	0.122	1.640	0.208
36	0.118	1.642	0.208
37	0.115	1.643	0.208
38	0.112	1.645	0.208
39	0.109	1.646	0.208
40	0.105	1.647	0.208
41	0.102	1.648	0.208
42	0.099	1.648	0.208
43	0.095	1.649	0.207
44	0.092	1.649	0.207
45	0.089	1.650	0.207
46	0.086	1.650	0.207
47	0.082	1.651	0.207
48	0.079	1.651	0.207
49	0.076	1.651	0.207
50	0.073	1.651	0.207
51	0.069	1.651	0.207
52	0.066	1.652	0.207
53	0.063	1.652	0.207
54	0.060	1.652	0.207
55	0.056	1.652	0.207
56	0.053	1.652	0.207
57	0.050	1.652	0.207
58	0.046	1.652	0.207
59	0.043	1.652	0.207
60	0.040	1.652	0.207

Table IV

Constant Dollars
(i = 3.7%)

For present worth and levelizing calculations if the effect of inflation is not included.

f Year	v^f	a_f	f Year	v^f	a_f
1	.9643	0.964	31	.3242	18.264
2	.9299	1.894	32	.3127	18.577
3	.8967	2.791	33	.3015	18.878
4	.8647	3.656	34	.2908	19.169
5	.8339	4.490	35	.2804	19.449
6	.8041	5.294	36	.2704	19.720
7	.7754	6.069	37	.2607	19.980
8	.7478	6.817	38	.2514	20.232
9	.7211	7.538	39	.2425	20.474
10	.6954	8.233	40	.2338	20.708
11	.6706	8.904	41	.2255	20.933
12	.6466	9.551	42	.2174	21.151
13	.6236	10.174	43	.2097	21.361
14	.6013	10.775	44	.2022	21.563
15	.5799	11.355	45	.1950	21.758
16	.5592	11.914	46	.1880	21.946
17	.5392	12.454	47	.1813	22.127
18	.5200	12.974	48	.1748	22.302
19	.5014	13.475	49	.1686	22.470
20	.4835	13.959	50	.1626	22.633
21	.4663	14.425	51	.1568	22.790
22	.4496	14.875	52	.1512	22.941
23	.4336	15.308	53	.1458	23.087
24	.4181	15.726	54	.1406	23.227
25	.4032	16.129	55	.1356	23.363
26	.3888	16.518	56	.1307	23.494
27	.3750	16.893	57	.1261	23.620
28	.3616	17.255	58	.1216	23.741
29	.3487	17.603	59	.1172	23.859
30	.3362	17.940	60	.1131	23.972

Constant Dollars
(i = 3.7%)

Table V

Levelizing factor $\underline{L_n}$ based on no inflation and an annual real escalation rate $\underline{e_r}$ as indicated.

% e_r	L_{10}	L_{20}	L_{30}
0.0	1.000	1.000	1.000
0.2	1.010	1.019	1.026
0.4	1.021	1.038	1.053
0.6	1.032	1.058	1.081
0.8	1.043	1.078	1.110
1.0	1.054	1.099	1.140
1.2	1.065	1.120	1.171
1.4	1.076	1.142	1.204
1.6	1.087	1.164	1.237
1.8	1.099	1.187	1.272
2.0	1.110	1.210	1.308
2.2	1.122	1.234	1.345
2.4	1.134	1.258	1.383
2.6	1.146	1.283	1.424
2.8	1.158	1.309	1.465
3.0	1.170	1.335	1.508
4.0	1.234	1.477	1.749
5.0	1.302	1.637	2.040

Table VI_N

Constant Dollars

(i = 3.7%)

Book Life (n) 30 Years
Tax Recovery (m) 10 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.103	0.100	0.103
2	0.099	0.192	0.101
3	0.093	0.275	0.099
4	0.087	0.351	0.096
5	0.082	0.419	0.093
6	0.077	0.481	0.091
7	0.073	0.537	0.089
8	0.070	0.590	0.086
9	0.067	0.638	0.085
10	0.065	0.683	0.083
11	0.063	0.726	0.082
12	0.063	0.766	0.080
13	0.062	0.805	0.079
14	0.061	0.841	0.078
15	0.060	0.876	0.077
16	0.059	0.909	0.076
17	0.058	0.941	0.076
18	0.058	0.971	0.075
19	0.057	0.999	0.074
20	0.056	1.026	0.074
21	0.055	1.052	0.073
22	0.054	1.076	0.072
23	0.053	1.099	0.072
24	0.053	1.121	0.071
25	0.052	1.142	0.071
26	0.051	1.162	0.070
27	0.050	1.181	0.070
28	0.049	1.199	0.069
29	0.048	1.215	0.069
30	0.048	1.231	0.069

Table VI_F

Constant Dollars
(i = 3.7%)

Book Life (n) 30 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.103	0.100	0.103
2	0.100	0.193	0.102
3	0.096	0.279	0.100
4	0.091	0.358	0.098
5	0.087	0.430	0.096
6	0.083	0.496	0.094
7	0.079	0.558	0.092
8	0.076	0.614	0.090
9	0.073	0.667	0.088
10	0.070	0.716	0.087
11	0.068	0.761	0.085
12	0.065	0.803	0.084
13	0.064	0.843	0.083
14	0.062	0.880	0.082
15	0.060	0.915	0.081
16	0.059	0.948	0.080
17	0.058	0.980	0.079
18	0.058	1.010	0.078
19	0.057	1.038	0.077
20	0.056	1.065	0.076
21	0.055	1.091	0.076
22	0.054	1.115	0.075
23	0.053	1.138	0.074
24	0.053	1.160	0.074
25	0.052	1.181	0.073
26	0.051	1.201	0.073
27	0.050	1.220	0.072
28	0.049	1.238	0.072
29	0.048	1.254	0.071
30	0.048	1.270	0.071

Table VI_H

Constant Dollars
($i = 3.7\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge $P_{f,m,n}$
1	0.090	0.087	0.090
2	0.087	0.168	0.089
3	0.083	0.243	0.087
4	0.079	0.311	0.085
5	0.075	0.374	0.083
6	0.072	0.431	0.081
7	0.068	0.484	0.080
8	0.065	0.533	0.078
9	0.063	0.578	0.077
10	0.060	0.620	0.075
11	0.058	0.659	0.074
12	0.057	0.696	0.073
13	0.055	0.731	0.072
14	0.054	0.763	0.071
15	0.053	0.794	0.070
16	0.052	0.823	0.069
17	0.052	0.851	0.068
18	0.051	0.878	0.068
19	0.051	0.903	0.067
20	0.051	0.928	0.066
21	0.050	0.951	0.066
22	0.050	0.974	0.065
23	0.049	0.995	0.065
24	0.049	1.015	0.065
25	0.048	1.035	0.064
26	0.048	1.054	0.064
27	0.048	1.071	0.063
28	0.047	1.088	0.063
29	0.047	1.105	0.063
30	0.046	1.120	0.062

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Table VI_H

Constant Dollars
($i = 3.7\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.046	1.135	0.062
32	0.046	1.149	0.062
33	0.045	1.163	0.062
34	0.045	1.176	0.061
35	0.044	1.188	0.061
36	0.044	1.200	0.061
37	0.043	1.212	0.061
38	0.043	1.222	0.060
39	0.043	1.233	0.060
40	0.042	1.243	0.060
41	0.042	1.252	0.060
42	0.041	1.261	0.060
43	0.041	1.270	0.059
44	0.040	1.278	0.059
45	0.040	1.286	0.059
46	0.040	1.293	0.059
47	0.039	1.300	0.059
48	0.039	1.307	0.059
49	0.038	1.313	0.058
50	0.038	1.320	0.058
51	0.038	1.325	0.058
52	0.037	1.331	0.058
53	0.037	1.336	0.058
54	0.036	1.342	0.058
55	0.036	1.346	0.058
56	0.035	1.351	0.058
57	0.035	1.355	0.057
58	0.035	1.360	0.057
59	0.034	1.364	0.057
60	0.034	1.367	0.057

Table VI_{NO}

Constant Dollars
(i = 3.7%)

Book Life (n) 30 Years
Tax Recovery (m) 30 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f, m, n}$)	Levelized Carrying Charge ($P_{f, m, n}$)
1	0.116	0.112	0.116
2	0.114	0.218	0.115
3	0.112	0.319	0.114
4	0.110	0.414	0.113
5	0.108	0.504	0.112
6	0.106	0.589	0.111
7	0.104	0.670	0.110
8	0.102	0.746	0.109
9	0.100	0.817	0.108
10	0.097	0.885	0.108
11	0.095	0.949	0.107
12	0.093	1.009	0.106
13	0.091	1.066	0.105
14	0.089	1.120	0.104
15	0.087	1.170	0.103
16	0.085	1.218	0.102
17	0.083	1.262	0.101
18	0.081	1.304	0.101
19	0.079	1.344	0.100
20	0.076	1.380	0.099
21	0.074	1.415	0.098
22	0.072	1.448	0.097
23	0.070	1.478	0.097
24	0.068	1.506	0.096
25	0.066	1.533	0.095
26	0.064	1.558	0.094
27	0.062	1.581	0.094
28	0.060	1.603	0.093
29	0.058	1.623	0.092
30	0.055	1.641	0.091

Table VI_{HO}

Constant Dollars
(i = 3.7%)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.100	0.096	0.100
2	0.099	0.188	0.099
3	0.098	0.275	0.099
4	0.097	0.359	0.098
5	0.095	0.438	0.098
6	0.094	0.514	0.097
7	0.093	0.587	0.097
8	0.092	0.656	0.096
9	0.091	0.722	0.096
10	0.090	0.784	0.095
11	0.089	0.844	0.095
12	0.088	0.901	0.094
13	0.087	0.955	0.094
14	0.086	1.007	0.093
15	0.085	1.056	0.093
16	0.084	1.103	0.093
17	0.083	1.148	0.092
18	0.082	1.190	0.092
19	0.081	1.231	0.091
20	0.080	1.270	0.091
21	0.079	1.306	0.091
22	0.078	1.341	0.090
23	0.077	1.374	0.090
24	0.076	1.406	0.089
25	0.074	1.436	0.089
26	0.073	1.464	0.089
27	0.072	1.492	0.088
28	0.071	1.517	0.088
29	0.070	1.542	0.088
30	0.069	1.565	0.087

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Table VI_{HO}

Constant Dollars
(i = 3.7%)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.068	1.587	0.087
32	0.067	1.608	0.087
33	0.066	1.628	0.086
34	0.065	1.647	0.086
35	0.064	1.665	0.086
36	0.063	1.682	0.085
37	0.062	1.698	0.085
38	0.061	1.713	0.085
39	0.060	1.728	0.084
40	0.059	1.742	0.084
41	0.058	1.755	0.084
42	0.057	1.767	0.084
43	0.056	1.779	0.083
44	0.055	1.790	0.083
45	0.053	1.800	0.083
46	0.052	1.810	0.082
47	0.051	1.819	0.082
48	0.050	1.828	0.082
49	0.049	1.836	0.082
50	0.048	1.844	0.081
51	0.047	1.852	0.081
52	0.046	1.859	0.081
53	0.045	1.865	0.081
54	0.044	1.871	0.081
55	0.043	1.877	0.080
56	0.042	1.883	0.080
57	0.041	1.888	0.080
58	0.040	1.893	0.080
59	0.039	1.897	0.080
60	0.038	1.901	0.079

APPENDIX B

COST AND PERFORMANCE DATA

APPENDIX B

CONTENTS

Section		Page
App B.1	ECONOMIC EVALUATION COST DATA	App B-1
App B.2	PRIMARY FUEL DATA	App B-5
	Coal	App B-5
	Nuclear Fuel Cycle	App B-6
	Petroleum Prices	App B-7
App B.3	COAL CLEANING AND SYNTHETIC FUEL DATA	App B-23
	General Terms	App B-23
	Data Sheet Definitions	App B-23
App B.4	GENERATION DATA	App B-39
	General	App B-39
	Environmental Factors	App B-39
	Capital Cost Learning Curve	App B-39
	Regional Data	App B-41
	Conventional Generating Technology	App B-41
	New or Advanced Generating Technologies	App B-43
	Data Ratings	App B-43
	Generation Data Sheet Definitions	App B-44
App B.5	ENERGY STORAGE DATA	App B-101
App B.6	LOAD MANAGEMENT AND CONSERVATION (Not Completed)	App B-109
App B.7	ELECTRICAL TRANSMISSION	App B-111

APPENDIX B

EXHIBITS AND FIGURES

Page

GENERAL DATA

Exhibits

App B1-1 Specific Cost Data App B-2

FUEL DATA

Exhibits

App B2-1 Price Information for EPRI Reference Coals App B-8
App B2-2 Representative Delivered Coal Prices for EPRI Geographical Regions App B-9
App B2-3 Minemouth Coal Price Projections App B-10
App B2-4 Representative Coal Transportation Costs App B-12
App B2-5 Base Case Forecasts of National Coal Consumption App B-13
App B2-6 Base Case Forecasts of National Coal Production App B-14
App B2-7 Nuclear Fuel Price Projections App B-15
App B2-8 Delivered Fuel Oil Price Projections App B-16

Figures

App B2-1 EPRI Regional Systems App B-17
App B2-2 Coal Supply Regions App B-18
App B2-3 U_3O_8 Projected Price vs Demand App B-19
App B2-4 Projected U_3O_8 Price vs Time App B-20
App B2-5 Projected Nuclear Fuel Prices App B-21

COAL CLEANING AND SYNTHETIC FUEL DATA

Exhibits

App B3-1 Physical Coal Cleaning--Coarse Cleaning App B-27
App B3-2 Physical Coal Cleaning--Intensive Cleaning App B-28
App B3-3 Combined Physical/Chemical Coal Cleaning App B-29
App B3-4 H-Coal® Process--All Distillate Coal Liquids App B-30
App B3-5 Coal Liquid Upgrading for H-Coal® Process App B-32
App B3-6 Methanol from Coal App B-34
App B3-7 Intermediate Btu Gas-Texaco Gasifier App B-36

Figure Page

App B4-1 Capital Cost Learning Curve App B-40

GENERATION DATA

Exhibits

Regional Data

App B4-1a Regional Coal Power Plant Characteristics-Large Unit Size App B-50
App B4-1b Regional Coal Power Plant Characteristics-Intermediate Unit Size App B-51
App B4-2 Regional Nuclear Light Water Reactor Power Plant Costs App B-52
App B4-3 Regional Oil-Fired Combined-Cycle Power Plant Costs App B-53

Baseload Fossil Data

App B4-4 Coal-Steam with Wet Limestone FGD App B-54
App B4-5 Coal-Steam with Regenerative FGD App B-56
App B4-6 Advanced Pulverized Coal-Steam, Chiyoda FGD App B-58
App B4-7 Atmospheric Fluid Bed Combustion App B-60
App B4-8 Pressurized Fluid Bed Combustion-Combined Cycle App B-62
App B4-9 Gasification-Combined Cycle (Texaco) App B-64
App B4-10 Gasification-Combined Cycle (BGC Slagger) App B-66
App B4-11 Gasification-Fuel Cell-Combined Cycle (Texaco) App B-68
App B4-12 Gasifier-Gas-Fired Boiler (Combustion Engineering) App B-70
App B4-13 Magnetohydrodynamic (MHD)-Combined Cycle App B-72

Intermediate and Peaking Plant Data

App B4-14 Solid Solvent Refined Coal-Steam Power Plant App B-74
App B4-15 Liquid Fuel Steam Power Plant App B-76
App B4-16 Liquid Fuel Combined Cycle--Conventional App B-78
App B4-17 Liquid Fuel Combined Cycle--Advanced App B-80
App B4-18 Liquid Fueled Combustion Turbine--Conventional App B-82
App B4-19 Liquid Fueled Combustion Turbine--Advanced App B-84
App B4-20 Dispersed Fuel Cells App B-86

Renewable Resource Data

App B4-21 Geothermal-Binary App B-88
App B4-22 Solar Central Receiver App B-90
App B4-23 Wind Power App B-92
App B4-24 Municipal Solid Waste-Steam App B-94

Exhibit Page

Baseload Nuclear

App B4-25 Nuclear Light Water Reactor App B-96
App B4-26 Nuclear Liquid Metal Fast Breeder Reactor App B-98

ENERGY STORAGE DATA

Exhibits

App B5-1 Battery Storage System App B-102
App B5-2 Underground Pumped Hydro Storage System App B-104
App B5-3 Compressed Air Energy Storage App B-106

TRANSMISSION AND DISTRIBUTION DATA

Exhibits

App B7-1 Single Circuit AC Transmission Line Data App B-112
App B7-2 Transmission Line Capability in Terms of SIL App B-113
App B7-3 Circuit Breakers Installed Cost App B-115
App B7-4 Bulk Power Transformer Costs App B-117
App B7-5 Distribution Substation Transformer Costs App B-118

Appendix B

App B.1 ECONOMIC EVALUATION COST DATA

Specific data for performing economic evaluations using the economic premises defined in Chapter 3 are presented in Exhibit App B1-1. The data are intended to be representive of the wide range of actual values for the items listed. For consistency these values should be used in EPRI economic evaluations. An exception to the requirement is studies performed to provide an updated value for the item listed. In this case, the revised values will be incorporated into future updates of the TAG Data. The Special Items catagory is to be used only when the study does not internally compute the appropriate values.

Exhibit App B1-1

SPECIFIC COST DATA
(December 1980 Dollars)

	January 1981		Escalation Rate, %/Yr		30 Yr (1981-2010)
Item	Value	Units	Real	Apparent	Levelization Factor
Operating Labor	15.25	$/person hour	0.0	8.5	2.31
Water (river)	0.50[a]	$/1000 gal	0.0	8.5	2.31
Lime	42	$/ton	0.0	8.5	2.31
Limestone	12	$/ton	0.0	8.5	2.31
Land	5,500	$/acre	0.0	8.5	---
Disposal Charges[b]					
Sludge	10.30	$/ton (dry basis)	0.0	8.5	2.31
Dry, Granular Solids	5	$/ton	0.0	8.5	2.31
Waste Water (Always includes as part of plant capital and operating costs)					
By-Product Credits[c]					
Sulfuric Acid	50	$/ton	0.0	8.5	2.31
Sulfur	60	$/Long ton	0.0	8.5	2.31
Ammonia (anhydrous)	150	$/ton	0.0	8.5	2.31

---

[a] See footnotes on following page.

Exhibit App B1-1 (continued)

SPECIFIC COST DATA
(December 1980 Dollars)

Item	January 1981 Value	Units	Escalation Rate, %/Yr Real	Escalation Rate, %/Yr Apparent	30 Yr (1981-2010) Levelization Factor
Special Items[d]					
Electric power (in plant)	3.5	¢/kWh	0.4	9.0	2.44
Steam (in plant)					
0-70 psia	2.50	$/1000 lb	0.4	9.0	2.44
70-250 psia	3.10	$/1000 lb	0.4	9.0	2.44
250-2400 psia	4.90	$/1000 lb	0.4	9.0	2.44

---

[a] This is a raw water acquisition charge only. Intake structures, treating and pumping costs are to be included in plant capital and operating costs.

[b] Normally waste disposal facilities are to be included in the plant capital and operating costs. The changes shown here are representative of off-site disposal costs for special cases where on-site disposal is not included.

[c] By-product storage, shipping and, marketing facilities must be included in the plant capital and operating cost if these by-product credits are used.

[d] These special values are to be used only in studies of limited scope which do not internally produce electricity and steam costs. The values are based on a 2400 psi coal-fired power plant (RP1258-2).

App B.2 PRIMARY FUEL DATA

Potential future prices of major energy resources to the electric utility industry are presented in this section. The price projections are intended to be representative values for EPRI R&D planning studies. The prices are not intended to apply to specific utilities at specific sites. The prices are given on a regional basis for coal. National averages are given for uranium and oil. The prices presented are subject to many uncertainies. For oil prices, the world market uncertainties and domestic energy policies are the most significant. Coal price uncertainties are significantly related to uncertainties about the quantity and quality of the coal resources and to future labor productivity and environmental regulations, both for the mining and for the burning of coal. The uranium reserve data, uranium demand and spent fuel reprocessing policies are the areas of most significant uncertainty for uranium prices. All future fuel prices are very sensitive to demand which is a function of the general economic and political climate. As new price studies are made, which include refinements in these and other areas of uncertainty, the prices in this section will be updated.

The prices for the fuels are given in December 1980 dollars. No increase has been made for future years to account for the effect of inflation. The only increase in prices shown is the result of real price escalation in mining, resource depletion, and transportation, etc., that occurs in addition to inflation. In making studies using the data in this section, the effects of inflation must be added to the prices shown.

App B.2.1 Coal

The coal price projections are presented in three levels of detail. For studies that are directed only at technology comparisons using a reference coal, the cost data in Exhibit App B2-1 are adequate. Representative compositions for the three reference coals in Exhibit App B2-1 are presented in Tables 2-1 thru 2-3 in Chapter 2.

For studies that use the EPRI regions (shown in Figure App B2-1 and discussed in Chapter 6), the cost data for representative coals from each region is given in Exhibit App B2-2. It should be noted that the delivered price projections are for selected coals with a specific sulfur content range including a reasonable transportation charge. The price projections in Exhibit App B2-2 do not represent average prices for all types of coal sold in the region.

[redacted]

Exhibit App B2-3 provides minemouth price projections for 12 producing regions for coals of different sulfur contents. The producing regions are shown in Figure App B2-2. Characteristic costs for transporting coal from the producing regions to the EPRI regions are given in Exhibit App B2-4. The minemouth coal prices and transportation costs are intended to be used in studies that consider interregional coal shipment and require pricing data on coals with a wide range of sulfur contents.

The coal price projections were developed using the ICF coal model and are based on the regional coal consumption and production rates given in Exhibits App B2-5 and App B2-6. Since the projected coal consumption rates are relatively high, the corresponding price projections may be on the high side*. If lower coal consumption rates occur then the coal prices should also be lower.

The coal prices are based on the marginal cost of opening new mines. Actual coal prices in 1981 were generally somewhat below the values given here. However, for long-term studies the price projections form a consistent data base that reflects the higher cost of opening new mines in more difficult areas and should be reasonable approximation of future price trends.

All the prices are given in December 1980 dollars and the appropriate inflation factor must be added if the prices are to be used in studies using dollars of a different time period.

App B.2.2 Nuclear Fuel Cycle

The uranium prices presented in Figures App B2-3 and App B2-4 are based on projections from International Energy Associates Limited. The corresponding nuclear fuel costs were computed from information supplied by EPRI's Energy Study Center.

Figure App B2-3 gives projected U_3O_8 prices with no reprocessing as a function of cumulative demand. The gray area represents the price uncertainty. The impact of two different levels of installed nuclear capacity (160 GW and 200 GW in the year 2000) on projected U_3O_8 prices is shown in Figure App B2-4.

---

* The high coal consumption rates result from the assumption of a relatively low (160 GW) installed nuclear capacity in the year 2000.

Nuclear fuel prices based on the 160 GW (year 2000) case are shown in Figure App B2-4. A breakdown of the nuclear fuel prices for the 160 GW case is given in Exhibit App B2-7. It should be noted that although U_3O_8 prices are expected to be stable in the 1980s, the real cost of fuel processing is expected to escalate. Overall, U_3O_8 prices should be viewed as relatively uncertain due to potential changes in both demand and import policies.

All prices are given in December 1980 dollars and the effects of inflation must be added if a different time period is used in the analysis.

App B.2.3 Petroleum Prices

App B.2.3.1 Fuel Oil. Price projections for distillate (No. 2) and residual (No. 6) fuel oil are given in Exhibit App B2-8 on a national average basis. A range of future real price escalation rates is given to reflect the large uncertainty in these price projections. The escalation rates are intended to represent long-term averages and do not reflect year-to-year price variations.

Because the residual fraction of the crude oil barrel is increasing, the escalation rate for residual oil may be somewhat lower than the escalation rate for distillate oil.

The range of escalation rates given (2 to 4% per year, real) encompasses the values typically used in 1981 studies by several energy companies and data analyses organizations.

A typical analysis of distillate fuel oil is given in Table 2-4.

App B.2.2.2 Natural Gas. Future natural gas prices and availability for utility use is very uncertain. For long-term studies that require natural gas prices, it is recommended that prices equivalent (on a Btu basis) to the distillate fuel oil projections be used.

Exhibit App B2-1

PRICE INFORMATION FOR EPRI REFERENCE COALS
(In $\$/10^6$ Btu)

Coal	Delivery Region	1981[a] Dec. 1980$	1981-2010 Escalation Real %/yr	1981-2010 Escalation Apparent %/yr[b]
Illinois No.6[c]				
Minemouth	Midwest	1.45	0.8	9.4
Delivered	East/West Central	1.65	0.7	9.3
Western Subbituminous[d]				
Minemouth	West Great Plains	0.60	1.5	10.1
Delivered	East/West Central	1.30	1.2	9.8
Gulf Lignite[e]				
Minemouth	Gulf	0.80	2.9	11.7
Delivered[f]	South Central	0.85	2.8	11.6

---

[a] Cost reference point is beginning of year 1981.

[b] Includes an average inflation rate of 8.5%/yr. for 1981-2010.

[c] Coal composition given in Table 2-1, page 2-10.

[d] Coal composition given in Table 2-2, page 2-11.

[e] Coal composition given in Table 2-3, page 2-13.

[f] Power plant is assumed to be near the minemouth.

Exhibit App B2-2

REPRESENTATIVE DELIVERED COAL PRICES FOR EPRI GEOGRAPHICAL REGIONS
(In $\$/10^6$ Btu, Constant Dec. 1980 Dollars)

Region	Nominal Sulfur Content ($lbS/10^6$ Btu)[c]	1981[ab]	1985	1990	1995	2000	2010
Northeast, Bituminous	0.9-1.7	2.15	2.45	2.60	2.70	2.75	3.15
Southeast, Bituminous	0.9-1.7	1.90	2.20	2.35	2.45	2.50	2.85
East Central, Bituminous	1.7+	1.65	1.75	1.80	1.80	1.90	2.05
West Central							
Bituminous	1.7+	1.60	1.70	1.75	1.75	1.80	2.00
Subbituminous	0.6-0.9	1.30	1.50	1.50	1.55	1.65	1.80
South Central, lignite	0.9-1.7	0.85	1.00	1.15	1.40	1.65	1.95
West, Bituminous	0.6-0.9	1.20	1.20	1.20	1.40	1.50	1.75

---

[a] 1981 prices based on extrapolation from 1985-1990 price trend. Actual 1981 prices were generally lower due to depressed market conditions.

[b] Cost reference point is January of the respective years.

[c] Note: 1 lb $S/10^6$ Btu = 2 lb $SO_2/10^6$ Btu if all sulfur is converted to SO_2 on combustion.

Exhibit App B2-3

MINEMOUTH COAL PRICE PROJECTIONS [a,b,c]
(In $\$/10^6$ Btu, Constant December 1980 Dollars)

SUPPLY REGION/Sulfur Content[d]	1981[e]	1985	1990	1995	2000	2010
Northern Appalachia						
Low	1.91	2.04	2.18	2.35	2.45	2.82
Low-Medium	1.83	1.98	2.14	2.27	2.34	2.73
High-Medium	1.60	1.73	1.88	1.96	2.04	2.41
High	1.25	1.46	1.71	1.79	1.86	2.09
Central Appalachia						
Low	1.71	1.84	1.99	2.13	2.27	2.70
Low-Medium	1.64	1.80	1.98	2.12	2.26	2.66
High-Medium	1.60	1.74	1.90	1.99	2.08	2.41
High	1.58	1.67	1.78	1.85	1.90	2.16
Southern Appalachia						
Low	1.83	2.04	2.27	2.47	2.59	2.93
Low-Medium	1.82	2.02	2.19	2.39	2.54	3.22
High-Medium	1.82	1.93	2.05	2.19	2.30	2.55
Midwest						
Low-Medium	1.82	1.93	2.05	2.16	2.30	2.54
High-Medium	1.60	1.72	1.85	1.92	2.02	2.20
High	1.44	1.48	1.52	1.54	1.60	1.77
Eastern Northern Great Plains						
Low	0.73(L)	0.72(L)	0.72(L)	0.74(L)	0.81(L)	0.89(L)
Low-Medium	0.72(L)	0.71(L)	0.71(L)	0.72(L)	0.77(L)	0.84(L)
High-Medium	0.42(L)	0.50(L)	0.60(L)	0.65(L)	0.71(L)	0.78(L)
Western Northern Great Plains						
Low	0.72	0.94	1.23	1.34	1.46	1.67
	0.63(S)	0.64(S)	0.65(S)	0.66(S)	0.73(S)	0.94(S)
Low-Medium	0.72	0.93	1.20	1.31	1.43	1.64
	0.58(S)	0.59(S)	0.60(S)	0.64(S)	0.72(S)	0.91(S)
High-Medium	0.70	0.93	1.23	1.37	1.37	1.62
	0.40(S)	0.45(S)	0.69(S)	0.61(S)	0.62(S)	0.73(S)
	--	--	--	1.41	1.51	1.72
Central West						
Low	1.68	1.84	2.02	2.18	2.30	2.63
Low-Medium	1.65	1.81	1.99	2.10	2.18	3.06
High-Medium	1.61	1.76	1.92	2.06	2.19	2.44
High	1.60	1.67	1.67	1.65	1.74	1.87

---

[a] See footnotes at end of table.

Exhibit App B2-3 (continued)

MINEMOUTH COAL PRICE PROJECTIONS [a,b,c]
(In $/10^6 Btu, Constant December 1980 Dollars)

SUPPLY REGION/Sulfur Content[d]	1981[e]	1985	1990	1995	2000	2010
Gulf						
Low-Medium	--	--	1.54(L)	1.91(L)	1.95(L)	2.08(L)
High-medium	0.79(L)	0.91(L)	1.05(L)	1.34(L)	1.56(L)	1.88(L)
Rocky Mountain						
Low	1.06	1.14	1.23	1.35	1.48	1.67
	1.01(S)	1.04(S)	1.07(S)	1.08(S)	1.13(S)	1.30(S)
Low-Medium	1.12	1.18	1.24	1.33	1.41	1.62
High-Medium	0.87	1.01	1.17	1.29	1.40	1.59
	--	--	--	--	1.22	
Southwest						
Low	1.05	1.14	1.24	1.45	1.56	1.94
Low-Medium	1.16	1.17	1.15	1.33	1.43	1.68
	0.83(S)	1.06(S)	0.83(S)	1.00(S)	1.09(S)	1.22(S)
High-Medium	0.83(S)	0.95(S)	0.83(S)	0.95(S)	1.04(S)	1.10(S)
Northwest						
Low	1.52	1.98	2.58	2.69	2.81	3.50
High-Medium	0.97(S)	1.36(S)	1.90(S)	2.06(S)	2.15(S)	2.33(S)
High	1.09	1.46	1.96	2.08	2.18	2.40
Alaska	--	--	--	0.96(S)	1.05(S)	1.24(S)

---

[a] All undesignated prices are for bituminous coal.
(S) Signifies subbituminous coal
(L) Signifies lignite coal.

[b] Prices are weighted averages of all coal produced within a supply region, disaggregated by sulfur and heat content. For some regions, 1985 prices can be influenced by limits placed on productive capacity. This can result in 1985 prices exceeding those of subsequent years.

[c] Cost reference point is January of the respective years (expressed in Dec. 1980 dollars)

[d] Sulfur content:
Low - Less than 0.61 lbs. Sulfur/10^6 Btu (corresponds to 1.2 lb SO_2/10^6 Btu)
Low-Medium - 0.61-0.92 lbs. Sulfur/10^6 Btu
High-Meidum - 0.93-1.67 lbs. Sulfur/10^6 Btu
High - Greater than 1.67 lbs. Sulfur/10^6 Btu

[e] January 1981 prices based on extrapolation back from 1985-1990 price trend. Actual January 1981 prices were generally lower due to depressed market conditions. (Here Dec. 1980 dollars are equivalent to Jan. 1981 dollars.)

[redacted]

Exhibit App B2-4

REPRESENTATIVE COAL TRANSPORTATION COSTS 1981-2010[a]

(In $/$10^6$ Btu, Constant December 1980 Dollars)

Origin/Destination	Northeast												West			
	New England		Middle Atlantic		Southeast		East Central		West Central		South Central		Mountain		Pacific	
Region	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]	1981	1985 on[b]
No. Appalachia	0.56	0.72	0.28	0.37	0.91	1.16	0.16	0.21	--	--	--	--	--	--	--	--
Cent. Appalachia	0.53	0.67	0.34	0.44	0.32	0.41	0.31	0.40	--	--	--	--	--	--	--	--
So. Appalachia	--	--	--	--	0.15	0.19	--	--	--	--	--	--	--	--	--	--
Midwest	--	--	--	--	0.70	0.89	0.21	0.28	0.14	0.21	0.38	0.50	--	--	--	--
Central West	--	--	--	--	0.55	0.70	0.63	0.80	0.14	0.17	0.72	0.92	0.70	0.89	--	--
Gulf (all Lignite)	--	--	--	--	--	--	--	--	--	--	0.06	0.08	--	--	--	--
East. Northern Great Plains (all lignite)	--	--	--	--	--	--	--	--	0.06	0.08	--	--	0.06	0.08	--	--
West. Northern Great Plains	--	--	1.38	1.76	--	--	1.20	1.52	0.71	0.91	1.06	1.34	0.05	0.06	1.33	1.71
Rocky Mountain	--	--	1.02	1.30	1.23	1.56	0.97	1.23	0.63	0.80	0.83	1.06	0.04	0.05	0.78	0.99
Southwest	--	--	--	--	1.23	1.56	--	--	--	--	0.72	0.92	0.05	0.06	0.69	0.72
Northwest	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.05	0.06
Alaska	--	--	--	--	--	--	--	--	--	--	--	--	--	--	0.82	0.95

---

[a] Cost reference point is Jaunuary for the year shown.

[b] Assumes average of 4.5%/yr real escalation in transportation cost for period 1981-85. Assumes no real escalation in transportation costs after 1985.

Exhibit App B2-5

BASE CASE FORECASTS OF NATIONAL COAL CONSUMPTION[a]

(million tons)

End-User Sector	1979	1985	1990	1995	2000	2010
Electric Utilities	527.1	746.8	1,003.0	1,398.9	1,785.3	2,619.2
Industrial	65.0	109.2	177.7	255.4	307.0	377.6
Metallurgical	76.6	76.0	79.8	83.8	88.0	97.2
Residential/Commercial	5.0	5.4	5.9	6.6	7.3	8.9
Synthetics	--	20.0	43.2	86.8	174.2	348.7
Exports:						
Steam	14.8	32.5	56.3	91.1	121.2	197.6
Metallurgical	50.0	50.0	58.0	68.0	69.7	73.3
Total (Rounded)	738	1040	1424	1991	2553	3723

---

[a] Data on Tables App B2-5 and App B2-6 are aggregates from the Base Case model runs. Independent rounding is used for each table so that in some cases totals may not agree exactly from one table to another.

BEST DOCUMENT AVAILABLE

Exhibit App B2-6

BASE CASE FORECASTS OF NATIONAL COAL PRODUCTION
(million tons)

Coal Supply Region	1979	1985	1990	1995	2000	2010
Northern Appalachia	182.7	192.1	209.6	286.5	379.5	555.4
Central Appalachia	217.4	265.1	342.9	395.9	429.1	383.5
Southern Appalachia	23.9	23.9	22.7	21.0	26.0	19.7
Subtotal, Appalachia	424.0	481.1	575.2	703.4	834.4	958.6
Midwest	131.0	149.9	192.3	250.1	347.2	659.3
Eastern Northern Great Plains	14.9	27.1	30.6	41.0	58.3	109.5
Western Northern Great Plains	104.4	216.7	314.2	432.8	599.6	964.3
Subtotal, Northern Great Plains	119.3	243.8	344.8	473.8	657.9	1,073.8
Central West	13.2	15.5	20.6	30.2	34.0	64.8
Gulf	26.6	44.0	93.5	176.6	194.2	223.2
Rocky Mountains	25.9	52.2	85.7	142.1	218.0	406.4
Southwest	25.0	43.5	87.9	170.1	217.8	288.1
Northwest	5.7	8.9	22.9	25.0	25.8	14.9
Alaska	--	--	--	18.2	22.3	32.4
Subtotal, Rest of West	96.4	164.1	310.6	562.2	712.1	1,029.8
US Total	770.7	1,038.9	1,422.9	1,989.5	2,554.6	3,721.5
Imports	1.0	1.0	1.0	1.0	1.0	1.0
Total (Rounded)	772	1040	1424	1990	2553	3722

Exhibit App B2-7

NUCLEAR FUEL PRICE PROJECTIONS
(December 1980 Dollars)

Year[a]	Uranium(U_3O_8)[b]		Fuel[c] Processing	Inventory Carrying Charges	Total Fuel Price
	$/lb	$/$10^6$ Btu	$/$10^6$ Btu (U_3O_8)	$/$10^6$ Btu (U_3O_8)	$/$10^6$ Btu
1981	34	0.18	0.41	0.14	0.73
1985	34	0.18	0.43	0.15	0.76
1990	44	0.24	0.45	0.16	0.85
1995	55	0.31	0.48	0.17	0.96
2000	63	0.35	0.51	0.18	1.04
2005	72	0.40	0.54	0.19	1.13
2010	79	0.44	0.56	0.20	1.20
2015	87	0.48	0.59	0.21	1.28
2020	96	0.53	0.64	0.22	1.39

---

[a] Cost reference point is January of the respective years.

[b] Based on Installed Nuclear Capacity of 160 GW_e in year 2000 and 290 GW_e in year 2020.

[c] Conversion, enrichment, fabrication, and spent-fuel disposal

Exhibit App B2-8

DELIVERED FUEL OIL PRICE PROJECTIONS[a]
($\$/10^6$ Btu)

Fuel Oil	January 1981 Reference Initial Price (Dec. 1980 $)	Real Escalation Rate 1981-2010, %/yr.		
		Reference[b]	Medium[d]	High
Distillate	6.80	2	3	4
Residual[c] (less than 0.5% Sulfur)	5.15	2	3	4

---

[a] Petroleum prices and price trends are subject to a great deal of uncertainty since they are very dependent on political factors. The real escalation rates are long-term average values and are not intended to reflect yearly price fluctuations.

[b] The initial prices shown coupled with the Reference (2%/yr.) real escalation rate are consistent with the coal price projections shown in Tables App B2 and App B2-3.

[c] Due to high transportation costs, residual oil prices are very dependent on location and could vary by ±20% from the value shown.

[d] The medium escalation rate is recommended for long-term price projections.

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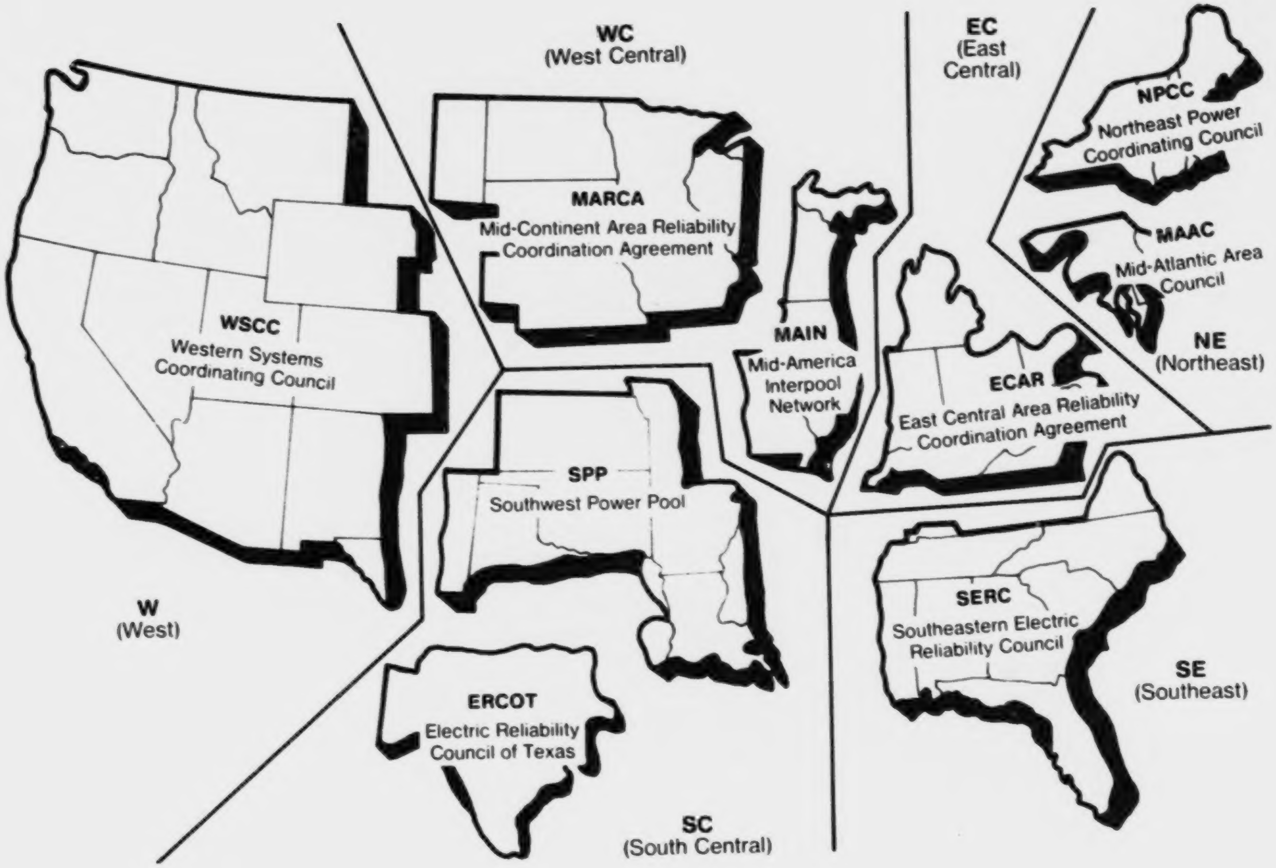
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NPCC
Northeast Power
Coordinating Council
MARCA
Mid-Continent Area Reliability
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MAAC
Mid-Atlantic Area
Council
WSCC
Western Systems
Coordinating Council
MAIN
Mid-America
Interpool
Network
NE
(Northeast)
ECAR
East Central Area Reliability
Coordination Agreement
SPP
Southwest Power Pool
W
(West)
SERC
Southeastern Electric
Reliability Council
SE
(Southeast)
ERCOT
Electric Reliability
Council of Texas
SC
(South Central)

Figure App B2-1 EPRI Regional Systems.

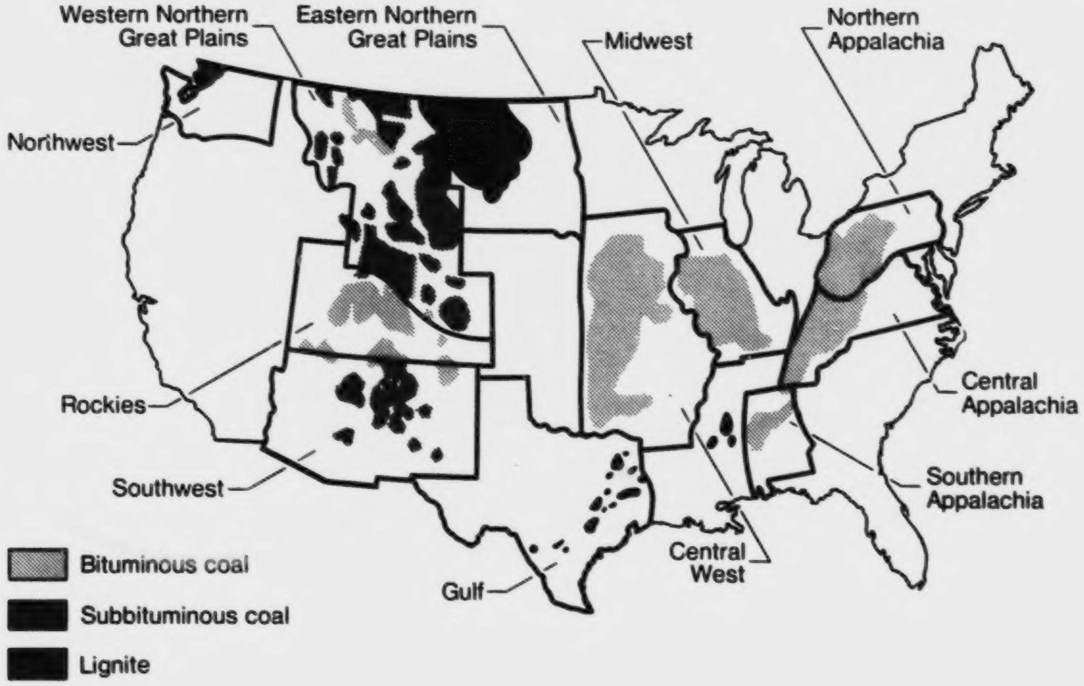
Western Northern Great Plains
Eastern Northern Great Plains
Midwest
Northern Appalachia
Northwest
Rockies
Southwest
Gulf
Central West
Central Appalachia
Southern Appalachia
▨ Bituminous coal
■ Subbituminous coal
■ Lignite

Figure App B2-2 Coal Supply Regions

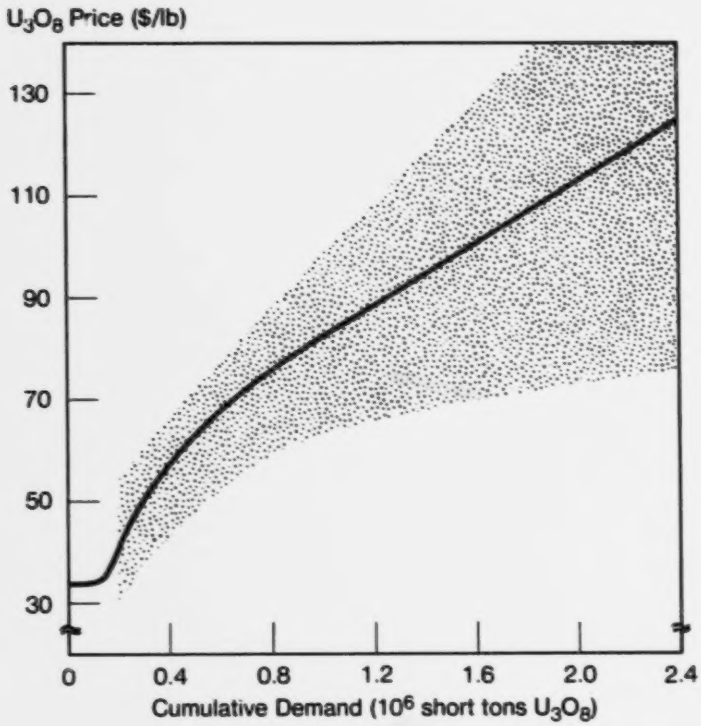

Figure App B2-3 U_3O_8 Projected Price Versus Cumulative Demand in Constant December 1980 Dollars (0.2 tails)

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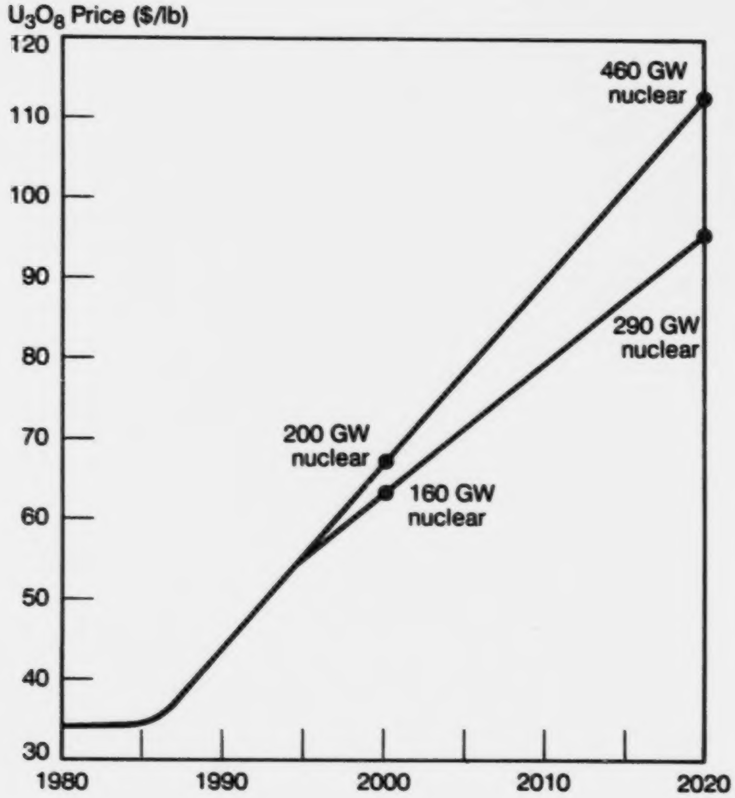

Figure App B2-4 Projected U_3O_8 Price in Constant December 1980 Dollars (0.2% tails and no reprocessing)

[redacted]

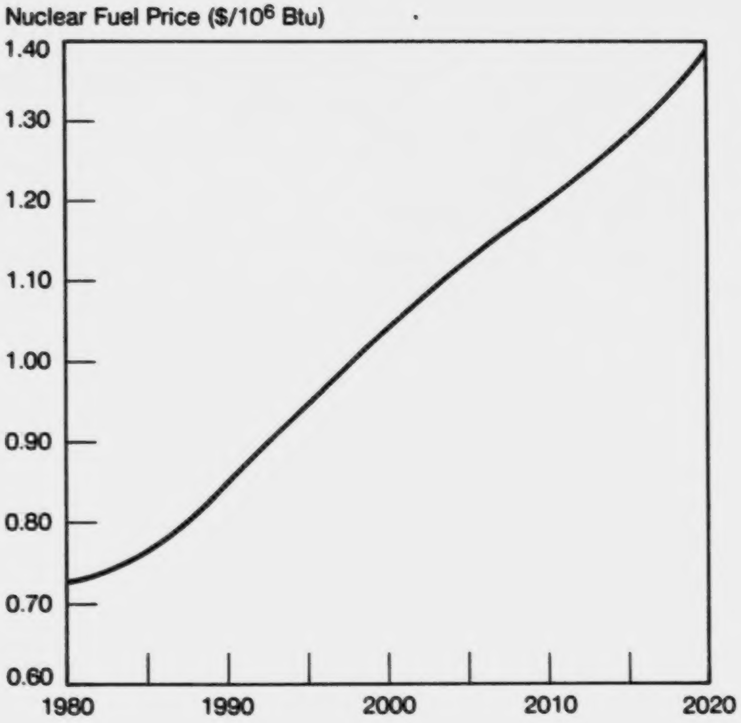

Figure App B2-5 Projected Nuclear Fuel Prices for a Nuclear Capacity of 160 GW(e) in 200 and 290 GW(e) in 2020 in Constant December 1980 Dollars

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[redacted]

App B.3 COAL CLEANING AND SYNTHETIC FUEL DATA

App B.3.1 General Items

Data sheets giving cost and performance information on coal-cleaning and synthetic fuel plants are presented in this section.

In general the information is developed in EPRI sponsored studies and represents the costs and performance that are expected to occur when the technology is in a mature state of development. The probable cost history of a new technology as it proceeds from a first commercial plant to a mature process is discussed in more detail in Section App B4.

Capital and operating costs and raw material (coal) requirements for some representative coal-cleaning and synthetic fuel plants are given in Exhibits App B3-1 through App B3-7. Synthetic fuel plants produce a manufactured product. How this product is priced depends on many things including the type of industry, the type of financing, and the degree of risk involved in the first plants.

The Engineering and Economic Evaluation Program in the Advanced Power Systems Division has a financial evaluation computer program that can be used along with the data in this section to make synthetic fuel price projections with various types of financial assumptions.

App B.3.2 Data Sheet Definitions

The following material briefly defines the data entry items given in Exhibits App B3-1 through App B3-7.

Projected First Commercial Operation, Yr.

If the technology is not already available, this item represents an estimate of the earliest date that a large commercial plant would be in operation. The data are based on an orderly and successful development. Since most technology development programs have unexpected delays and unsuccessful steps that must be repeated, the actual first commercial operation date is likely to be later than the one shown.

Plant Location

Because of variations in climatic factors, coal types, labor productivety, etc., the plant location can have a large influence on plant cost (variations of ±20% are not unusual). Many of EPRI cost estimates are based on an Illinois location using Illinois No. 6 coal. These estimates are assumed to be representative of the East Central and West Central regions shown in Figure App B2-1 and designated as East/West Central on the data sheets.

Nominal Plant Size

The maximum instantaneous production rate is given on an hourly or daily basis. Where the yearly production rate is also given, the plant capacity factor is included (see next definition).

Nominal Capacity Factor

The expected plant output in a normal year (not the startup year) divided by the plant output, if it ran at its maximum rated thoughout for a year, is the plant capacity factor (expressed as a percent).

Overall Thermal Efficiency

The overall thermal efficiency is the total energy/unit time in the fuel product streams divided by the total energy/unit time of the fuel feed materials, including purchased electricity (converted to fuel input equivalent at 10,000 Btu/kWh).

Total Plant Cost

This includes all capital costs as defined in Section 3.4 (Chapter 3) expressed at a single point in time (overnight construction). The capital cost per unit of capacity is given as the specific capital cost.

Startup, Inventory, Working Capital

The startup capital is computed in a manner similar to the preproduction costs discussed in Section 3.5.5 of Chapter 3. The inventory capital (or Working capital) is based on a 30-day (at full capacity) supply of raw materials (coal) and a 30-day supply of product solid and liquid fuels.

Total Capital Requirement

The total capital requirement is as defined in Section 3.5 of Chapter 3 but does not include AFDC since some potential synthetic fuel plant and coal-cleaning plant owners do not include AFDC charges in their financial analysis.

Normal Year Operating Cost

This is the operating cost for a normal year as opposed to a startup year. All materials and labor are included except coal. The operating costs per unit of capacity are given as the specific operating costs.

Feed Requirement

The feed requirement gives the amount of feed (coal) necessary to produce a unit of product fuel. This entry is used to calculate cost of feed per unit of product for a given feedstock price.

Product Quality

An indication of product types and quality is given in this entry. Direct comparision among various synfuels is often quite difficult because of differences in product quality (sulfur content, hydrogen content, physical form, etc.).

Exhibit App B3-1

PHYSICAL COAL CLEANING - COARSE CLEANING[b]
(All Costs in December 1980 Dollars)

	Coal Type	
	Illinois No. 6	Pittsburgh Seam
Projected First Commercial Operation, Yr	Current	Current
Plant Location (Region)	East/West Central	Northeast
Nominal Plant Size		
10^6 Tons/yr product	2.9	2.5
Tons/hr product	745	640
10^9 Btu/hr product	15.6	15.4
Nominal Capacity Factor, %	45	45
Overall Thermal Efficiency, %	95	94.6
Total Plant Investment		
Total Capital, 10^6 \$	19.1	18.5
Specific Capital, \$/ton/hr product	25,600	28,000
Startup, Inventory, Working Capital, 10^6 \$	2.5	2.6
Total Capital Requirement (No AFDC), 10^6 \$	21.6	21.1
Normal Year Operating Cost[a]		
Total 10^6 \$/yr	3.4	3.1
Specific \$/ton product	1.14	1.24
Feed Requirement, Btu Feed/Btu Product	1.05	1.05

Product Quality	Feed	Product	Feed	Product
% Sulfur	3.4	3.3	3.4	3.1
% Ash	16.5	12.0	15.0	11.3
% Moisture	12.6	12.6	8.0	8.0
Higher Heating Value, Btu/lb	9860	10,480	11,510	12,060
% Sulfur Reduction (lb S/10^6 Btu basis)	--	9.5	--	13.0

---

[a] Excluding coal feed.

[b] Reference Report: Cost Impact of Coal Cleaning on New Power Generation, EPRI CS-1622, March 1981.

Exhibit App B3-2

PHYSICAL COAL CLEANING - INTENSIVE CLEANING[b]
(All Costs in December 1980 Dollars)

	Coal Type	
	Illinois No. 6	Pittsburgh Seam
Projected First Commercial Operation, Yr	Current	Current
Plant Location (Region)	East/West Central	Northeast
Nominal Plant Size		
10^6 Tons/yr product	2.8	2.4
Tons/hr product	770	660
10^9 Btu/hr product	16.7	16.4
Nominal Capacity Factor, %	42	42
Overall Thermal Efficiency, %	94.7	95.1
Total Plant Investment		
Total Capital, 10^6 \$	34.8	30.6
Specific Capital, \$/ton/hr product	45.3	46.2
Startup, Inventory, Working Capital, 10^6 \$	3.6	3.3
Total Capital Requirement (No AFDC), 10^6 \$	38.4	33.9
Normal Year Operating Cost[a]		
Total 10^6 \$/yr	4.7	3.9
Specific \$/ton product	1.69	1.61
Feed Requirement, Btu Feed/Btu Product	1.05	1.05

Product Quality	Feed	Product	Feed	Product
Sulfur, % W	3.4	3.2	3.4	2.9
Ash, % W	16.5	9.2	15.0	8.7
Moisture, % W	12.6	12.6	8.0	8.0
Higher Heating Value, Btu/lb	9860	10,870	11,510	12,440
% Sulfur Reduction (lb S/10^6 Btu basis)	--	9.5	--	13.0

---

[a] Excluding coal feed.

[b] Reference Report: Cost Impact of Coal Cleaning on New Power Generation, EPRI CS-1622, March 1981.

[redacted]

Exhibit App B3-3

COMBINED PHYSICAL/CHEMICAL COAL CLEANING[b]
(All Costs in December 1980 Dollars)

	Illinois No. 6 Coal
Projected First Commercial Operation	1985
Plant Location (Region)	East/West Central
Nominal Plant Size	
10^6 Tons/yr product	2.5
Tons/hr product	325
10^9 Btu/hr product	7.18
Nominal Capacity Factor	90%
Overall Thermal Efficiency, %	82-85
Total Plant Cost (Range)	
Total Capital, 10^6 \$	200-275
Specific Capital, \$/ton/hr product	600-665
Startup, Inventory, Working Capital, 10^6 \$	15-20
Total Capital Requirement (No AFDC), 10^6 \$	215-295
Normal Year Operating Cost[a]	
Total 10^6 \$/yr	57-79
Specific \$/ton product	22-31
Feed Requirement, Btu Feed/Btu Product	1.07

Product Quality	Feed	Product
Sulfur, % W	3.4	1.8
Ash, % W	16.5	7.6
Moisture, % W	12.6	12.6
Higher Heating Value, Btu/lb	9860	11,060
% Sulfur Reduction (lb $SO_2/10^6$ Btu basis)	--	52.8

---

[a] Excluding coal feed.

[b] Reference Reports: Cost Impact of Coal Cleaning on New Power Generation, EPRI CS-1622, March 1981. Preliminary Evaluation of Chemical Coal Cleaning by Promoted Oxydesulfurization, EPRI EM-1044, April 1979.

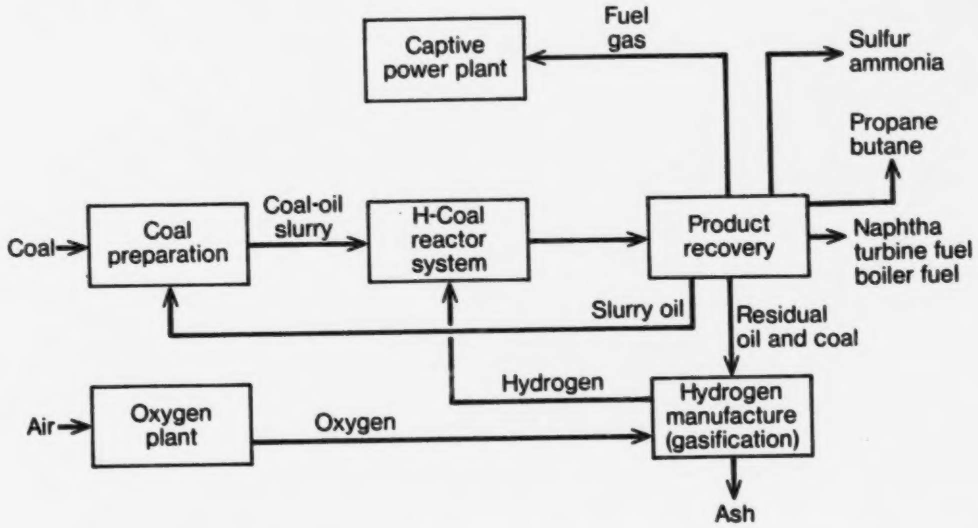
[redacted]

Exhibit App B3-4a

H-COAL PROCESS--ALL DISTILLATE COAL LIQUIDS

The overall facility consists of a coal liquefaction plant along with the support and general facilities needed for a self-sufficient operation. Feed Coal is crushed, dried, slurried with a recycle oil and liquefied by the H-Coal technology in which the coal and hydrogen react in the presence of a catalyst at elevated temperatures (above 800 F) and pressure (3000 psi) to produce distillate range material. The reactor effluent is separated by a series of flashes and by fractionation, with several streams being recycled to the reactor. Primary products include stabilized naphtha, turbine fuel and distillate boiler fuel.

Support units, in addition to coal crushing and drying, include the air separation plant, the hydrogen plant in which vacuum bottoms from the H-Coal operation are gasified and converted to hydrogen, a gas plant in which by-product propane and butane are recovered, a light [illegible]s separation unit for a recovering and recycling unreacted hydrogen, a sour water stripping unit, a sulfur recovery plant, and product storage and shipping facilities. All other necessary facilities, including an on-site captive power plant and a complete effluent treating system are included.


Captive power plant
Fuel gas
Sulfur ammonia
Propane butane
Coal
Coal preparation
Coal-oil slurry
H-Coal reactor system
Product recovery
Naphtha turbine fuel boiler fuel
Slurry oil
Residual oil and coal
Hydrogen
Air
Oxygen plant
Oxygen
Hydrogen manufacture (gasification)
Ash

[redacted]

Exhibit App B3-4b

H-COAL PROCESS--ALL DISTILLATE COAL LIQUIDS[a]
(All Costs in December 1980 Dollars)

	Illinois No. 6 Bituminous Coal	Wyodak Subbituminous Coal
Projected Earliest Commercial Operation, Yr	1987	1987
Plant Location--Minemouth	West Central	West
Nominal Plant Size-Full Capacity Rating		
10^9 Btu/day (HHV)	250	250
10^3 bbl/day FOE[b]	40	32
Nominal Capacity Factor	90	90
Overall Thermal Efficiency[c]	68.4	60.9
Total Plant Cost[d]		
Total Capital, 10^6 \$	1310	1500
Specific Capital, \$/bbl/day FOE Capacity	33,000	47,000
Startup, Working Capital, Land, Royalties, and Catalysts, 10^6 \$	105	100
Total Capital Requirement (excluding AFDC), 10^6 \$	1415	1600
Normal Year Operating Cost (excluding Coal)[d,e]		
Total 10^6 \$/yr	92	96
Specific \$/10^6 Btu Product	1.17	1.46
Coal Feed Requirements, Btu Coal/Btu Product	1.46	1.64

	Illinois Coal			Wyodak Coal		
		Fuel Oil			Fuel Oil	
Product Quality[f]	Naphtha	Turbine	Boiler	Naphtha	Turbine	Boiler
Amount 10^3 bbl/day	13.4	16.2	8.8	16	12.4	6.8
Boiling Range, °F	C_4-350	350-600	500-800	C_4-400	350-600	500-800
% W Sulfur	0.07	0.08	0.08	0.02	0.03	0.03
$ W Nitrogen	0.24	0.47	0.63	0.10	0.22	0.46
% W Hydrogen	13.8	10.1	8.6	14.0	11.4	9.4
Higher Heating Value 10^3 Btu/lb	19.8	18.5	17.8	19.9	19.0	18.2

---

[a] Reference Report: Engineering Evaluation of Conceptual Coal Conversion Plant Using the H-Coal Liquefaction Process, EPRI AF-1297, Dec. 1979.

[b] FOE = Fuel oil equivalent (6.3 x 10^6Btu/bbl) based on the higher heating value (HHV)

[c] (Btu of all products)/(Btu of all feed including fuel equivalent of electric power) x 100%. Excludes heating value of Ammonia and Sulfur.

[d] For a mature plant.

[e] Does not include potential by-product credits for ammonia and sulfur of 7.7 and 5.0 Million \$/yr for Illinois case and Wyodak case respectively.

[f] Not including propane & butane.

[redacted]

Exhibit App B3-5a

COAL LIQUID UPGRADING FOR H-COAL PROCESS
(Hydroprocessing H-Coal Liquids)

The three Liquid Product Streams (Naphtha, turbine fuel and boiler fuel) from the H-Coal liquefaction plant are further processed in catalytic hydrotreaters to reduce sulfur and nitrogen contents and produce higher hydrogen content fuels. The hydrogen feed is assumed to be supplied by a separate facility. The feed streams are produced by the Illinois coal case for the H-Coal plant in Exhibit App B3-4.

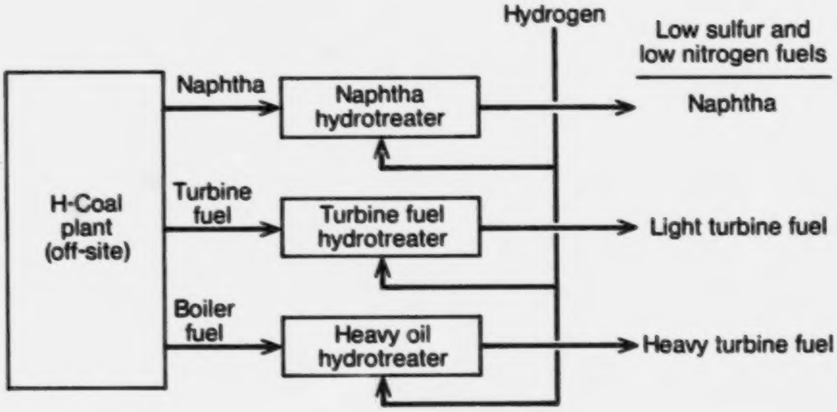

Hydrogen
Low sulfur and low nitrogen fuels
H-Coal plant (off-site)
Naphtha
Naphtha hydrotreater
Naphtha
Turbine fuel
Turbine fuel hydrotreater
Light turbine fuel
Boiler fuel
Heavy oil hydrotreater
Heavy turbine fuel

Exhibit App B3-5b

COAL LIQUID UPGRADING FOR H-COAL PROCESS (ILL. NO. 6 COAL)[a]
(All Costs in December 1980 Dollars)

	Coal Liquids From Ill. No. 6 Coal
Projected Earliest Commercial Operation, Yr	1987
Plant Location--Coal Conversion Plant Site	West Central
Nominal Plant Size (Processes Liquid H-Coal Product)[b]	2.5
10^9 Btu/day	225
10^3 bbl/day FOE[c]	36
Nominal Capacity Factor	90
Total Plant Cost[d]	
Total Capital, $\$ \times 10^6$	195
Specific Capital, \$/bbl/day FOE	5.4
Startup, Working Capital, Royalties & Catalysts, $\$ \times 10^6$	85
Total Capital Requirement (excluding AFDC), $\$ 10^6$	230
Normal Year Operating Cost (excluding Feed)[d]	
Total $\$10^6$/yr	63
Specific $\$/10^6$ Btu Product (Total Product Mix)	0.85[e]

Product Quality Estimates (See Exhibit App B3-4b for Feed)

	Naphtha	Turbine Fuel Light	Turbine Fuel Heavy
Amount, 10^3 bbl/day	13	16	9
Sulfur, %W	<0.01	<0.01	0.01
Nitrogen, %W	0.04	0.04	0.06
Hydrogen, %W	14.0	11.2	11.0
Higher Heating Value, 10^3 Btu/lb	19.8	19.0	18.8

---

[a] Reference Report: Economic Screening Evaluation of Upgrading Coal Liquids to Turbine Fuels, EPRI AF-710, March 1978.

[b] Hydroprocesses Liquid Products from H-Coal Plant (Ill. No. 6 Coal) shown in Exhibit App B3-4.

[c] FOE = Fuel oil equivalent (6.3×10^6 Btu/bbl).

[d] Based on hydrogen purchased at \$2.85/1000 SCF (95% H_2).

[e] Purchased hydrogen accounts for $\$0.60/10^6$ Btu of the value shown.

[redacted]

Exhibit App B3-6a

METHANOL FROM COAL

Texaco Gasification and ICI Methanol Synthesis

The overall facility consists of a coal-to-methanol plant along with the required support, utility, and off-site facilities to comprise a self-sufficient operation. Coal is gasified via Texaco partial oxidation technology using oxygen as the oxidant. The gasifier effluent stream is processed by shift conversion, COS hydrolysis, and Rectisol acid gas removal to produce a methanol synthesis gas. This gas is then processed, via the ICI low-pressure process, to produce methanol. Water formed during methanol synthesis is removed from the product by distillation. Purge gas from the methanol synthesis loop furnishes the fuel needs of the entire facility including on-site power generation for in-plant service. The primary product is a stabilized methanol stream suitable for use by the electric power industry as either turbine or boiler fuel.

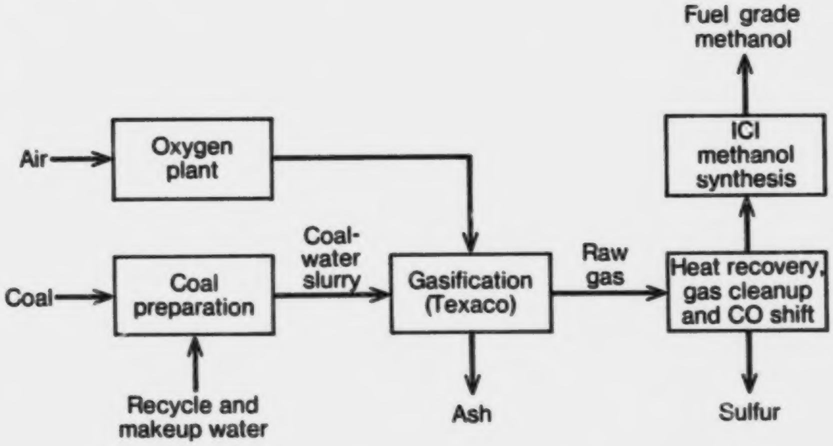

Fuel grade methanol
Air
Oxygen plant
ICI methanol synthesis
Coal-water slurry
Raw gas
Coal
Coal preparation
Gasification (Texaco)
Heat recovery, gas cleanup and CO shift
Recycle and makeup water
Ash
Sulfur

Exhibit App B3-6b

METHANOL FROM COAL[a]
Texaco Gasification and ICI Methanol Synthesis
(All Costs in Dec. 1980 Dollars)

	Illinois No. 6 Bituminous Coal
Projected Earliest Commercial Operation	1986
Plant Location--Minemouth	West Central
Nominal Plant Size--Full Capacity Rating	
10^9 Btu/day (HHV)	210
10^3 bbl/day FOE[b]	33
Nominal Capacity Factor	90
Overall Thermal Efficiency[c]	57.8
Total Plant Cost[d]	
Total Capital, 10^6\$	1320
Specific Capital \$/bbl/day FOE Capacity	40,000
Startup, Working Capital, Land, Royalties and Catalysts, 10^6\$	95
Total Capital Requirement (excluding AFDC), 10^6\$	1415
Normal Year Operating Cost (excluding coal)[d]	
Total \$/yr.	76
Specific \$/10^6Btu Methanol (HHV)	1.10
Coal Feed Requirements Btu Coal/Btu Product	1.73
Product Quality	
Higher Heating Value Btu/lb	9692
Lower Heating Value Btu/lb	8501
Volumetric Capacity bbl/day (42 gal/bbl)	79,000

---

[a] Reference Report: Coal to Methanol, An Engineering Evaluation of Texaco Gasification and ICI Methanol--Synthesis Route, EPRI AP1962, August 1981.

[b] FOE - Fuel oil equivalent (6.3 x 10^6Btu/bbl).

[c] (Btu of all products) / (Btu of all feed including fuel equivalent of electric power) x 100%. Excludes heating value of sulfur and ammonia.

[d] For a mature plant.

[redacted]

Exhibit App B3-7a

INTERMEDIATE BTU GAS--TEXACO GASIFIER

In the Texaco version of an intermediate Btu coal gasification process, pulverized coal in a concentrated water slurry is pumped into the entrained flow gasifier where partial oxidation with oxygen produces an intermediate Btu fuel gas (~ 300 Btu/standard cubic foot). The gas leaving the gasifier at 600 psi and 2400°F passes through a heat recovery section and enters a gas cleanup section where particulates, ammonia and sulfur compunds are removed. Electric power in excess of plant needs is generated from waste heat and by power recovery from pressure reduction of the product fuel gas stream. The fuel gas leaves the plant boundry at 35 psig and is assumed to be consumed in a nearby industrial complex or power plant.

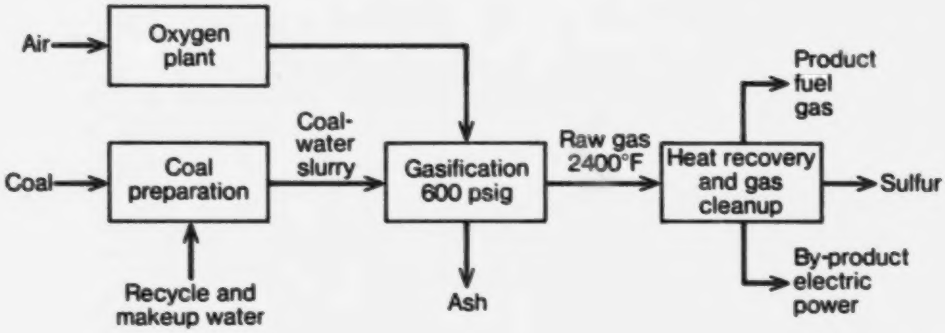

Air
Oxygen plant
Coal
Coal preparation
Coal-water slurry
Gasification 600 psig
Recycle and makeup water
Ash
Raw gas 2400°F
Heat recovery and gas cleanup
Product fuel gas
Sulfur
By-product electric power

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Exhibit App B3-7b

INTERMEDIATE BTU GAS--TEXACO GASIFIER[a]
(All Costs in December 1980 Dollars)

	Illinois No. 6 Bituminous Coal
Projected Earliest Commercial Operation	1986
Plant Location--Industrial Area	West Central
Nominal Plant Size--Full Capacity Rating	
10^9 Btu/day Fuel Gas (HHV)	168
By-product Power Production, MW	150
Nominal Capacity Factor	90
Overall Thermal Efficiency[b]	72.4
Total Plant Cost[c]	
Total Capital, $10^6\$$	570
Specific Capital $\$/10^6$ Btu/hr of Fuel Gas	82,000
Startup, Inventory Capital[e], Land, Royalties and Chemicals	35
Total Capital Requirements (excluding AFDC), $10^6\$$	605
Normal Year Operating Cost (excluding Fuel)[c]	
Total \$/yr	20
Specific $\$/10^6$ Btu Fuel Gas	0.35
Coal Feed Requirements, Btu Coal/Btu Fuel Gas	1.47
Product Information	
By-product electricity, MW capacity	150
Kwh/10^6 Btu Gas Product	21.5
Gas Quality	
Higher Heating Value Btu/SCF	287
Hydrogen (H_2), % mol	35
Carbon monoxide (CO), % mol	50
Delivery Pressure, psig	35

---

[a] Reference Report: Economics of Texaco Gasification Process for Fuel Gas Production, RP239, Task 18, Case EXT-SS, in Publication.

[b] (Btu of all products) / (Btu of all feed including fuel equivalent in electric power) x 100%. By-product electric power at 3412 Btu/kwh. Heating value of Ammonia and Sulfur excluded.

[c] Mature plant basis.

[d] Based on fuel gas production.

[e] Inventory capital based on one month coal supply. No product inventory or working capital is included.

[redacted]

App B.4 GENERATION DATA

App B.4.1 General

This section contains power plant cost and performance estimates for currently available and new technologies. In general, the estimates were based on the economic and design factors presented in Chapters 2 and 3. The estimates are intended to be for representative power plants and have been normalized where possible to produce a consistent data base for EPRI planning studies. The estimates are not intended to apply to specific utilites at specific sites.

App B.4.2 Environmental Factors

The cost and performance estimates contained in this section are based on meeting the New Source Performance Standards (NSPS) that were promulgated in 1979. Any stricter environmental standards may significantly affect the relative costs of the alternatives and may cause regional variations different from those contained in this Guide.

App B.4.3 Capital Cost Learning Curve

Experience has shown that cost estimates for a new technology made early in its development period are often low by a factor of two or more (expressed in constant dollars) compared to the actual costs of the first commercial version of the technology.

Another effect that occurs after a new technology is commercialized is a reduction in cost (in constant dollars) as improved versions of the new technology are subsequently built. This effect is sometimes referred to as the learning curve. When the new technology is well established and being produced by many vendors in competition with each other, the technology is referred to as "mature".

These two effects on capital cost are illustrated in Figure App B4-1 where the capital cost per unit of capacity expressed in constant dollars is plotted versus time for a hypothetical new generating technology. The units of time are the design/construction period of the plant. In order for the learning experience of one plant is to be incorporated into another plant, the plants must be built in series. Therefore, plants with a long design/construction time will take many years to reach mature plant costs. If regulations change then maturity will be delayed further.

[redacted]

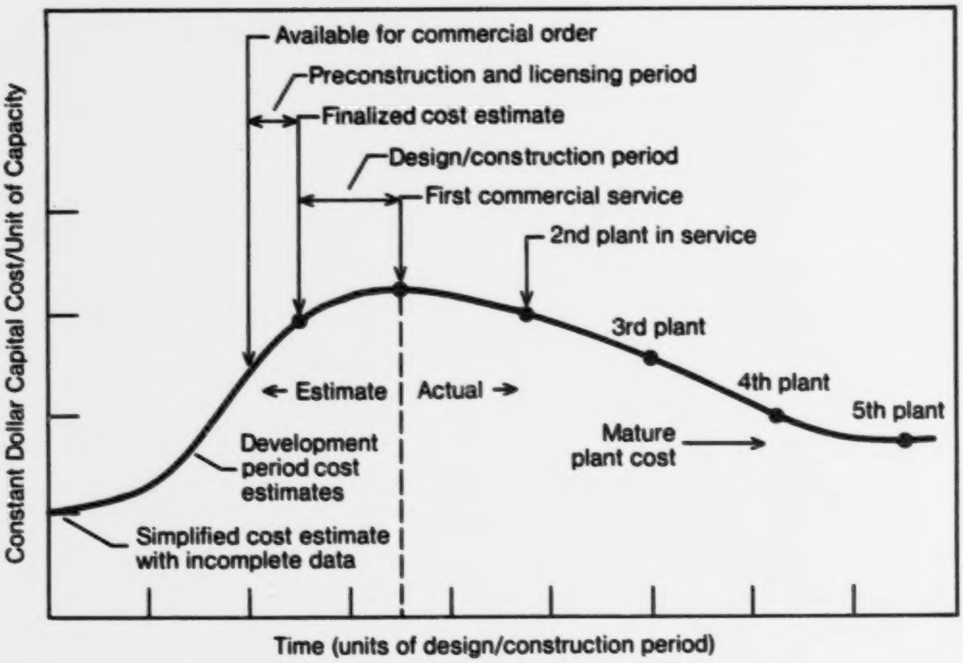

Figure App B4-1 Capital Cost Learning Curve Illustration

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The cost estimates for new technologies presented in this Guide are intended to represent mature plant costs. The first commercial versions of technologies could be significantly more expensive than the costs given here.

App B.4.4 Regional Data

Cost and performance data for currently available conventional generating plants are presented on a regional basis in Exhibits App B4-1 through App B4-3. The regions are given in Figure App B2-1. Climatic factors, coal type as well as labor and material rates affect conventional coal plant regional costs. Nuclear plant regional cost differences are primarily a function of seismic requirements and labor and material rates.

Cost and performance data for new technologies are generally only available for a limited number of regions and a limited number of fuel types. Most of the data given in Exhibits App B4-4 through App B4-26 are representative for the East Central and West Central regions designated as East/West Central.

App B.4.5 CONVENTIONAL GENERATING TECHNOLOGY

App B.4.5.1 Conventional Pulverized Coal Power Plants

Two coal plants, one with two, 1000 MW supercritical units and the other with two, 500 MW subcritical units, have been selected as the reference designs. If only one unit were built, the cost per kW for the plant would increase by 1/0.96. The cost for a unit between 500 MW and 1000 MW can be estimated using the following equation:

$$C = C_o \left(\frac{MW_o}{MW}\right)^{0.15}$$

where

C = new plant cost in \$/kW
C_o = base plant cost in \$/kW
MW_o = base plant size in MW
MW = new plant size in MW

The reference coal-fired plant designs were prepared by Bechtel (EPRI PE1865).

App B.4.5.2 Conventional Light Water Reactor Nuclear Plants

There is currently a large amount of uncertainty as to the cost of future nuclear plants. The data presented in this guide are very likely at the low end of the cost range. Design and operating changes that have occurred since the 1979 Three Mile Island accident have not been incorporated into the data. In 1982, EPRI expects to have revised and up-to-date nuclear plant cost estimates.

A relationship of size versus dollars per kW captial costs was developed and is applicable for light water reactor plants in the range of 500-1200 MW. This relationship is as follows:

$$C = C_o \left(\frac{MW_o}{MW}\right)^{0.47}$$

where

C = new plant cost in \$/kW
C_o = base plant cost in \$/kW
MW_o = base plant size in 1000 MW
MW = new plant size in MW

App B.4.5.3 Oil Steam Power Plants

The data for new oil steam power plants for utility service are rather limited since no future orders for this type of plant are expected.

App B.4.5.4 Combustion Turbine

The cost data for combustion turbines are national averages and are based on published purchasing information. The heat rates listed are based on the higher heating value of the fuel. This should be distinguished from quoting the fuel consumption rate for combustion turbines in Btu/kWh referenced to the lower heating value of the fuel burned, often used for combustion process analysis by turbine manufactures.

App B.4.5.5 Combustion Turbine - Combined Cycle

The conventional oil-fired combustion turbine combined cycle plants costs are based on a study by Bechtel (EPRI AF610) and represent a composite plant configuration.

App B.4.6 New or Advanced Generating Technologies

The cost and performance data for new technologies given in Exhibits App B4-4 through App B4-26 are produced in wide range of conceptual design studies by EPRI contractors. The principal report used for developing the data is referenced at the bottom of the cost and performance tables. In many cases minor adjustments were made to the costs to reflect the current design and economic premises that were discussed in Chapters 2 and 3.

App B.4.7 Data Ratings

The following two rating systems are used to give an overall confidence level to the data presented in Appendix B.

Technology Development Rating

This rating gives an indication of the developmental status for the technology. The following table is used in assigning the rating.

Rating	Description
1	No system hardware development
2	Concept supported by laboratory studies and initial hardware development
3	Concept supported by small pilot facility
4	Concept verified by integrated demonstration plant
5	Significant commercial experience (more than 5 commercial plants)

Design/Cost Estimate Rating. This rating gives an indication of the level of effort involved in the design and cost estimate that supports the data presented in the Technical Assessment Guide. The following table gives the rating definitions.

[redacted]

Rating[a]	Description
1	Technology design/cost goal (or value developed from literature data)
2	Simplified process design (Class I design and cost estimate[b])
3	Preliminary process design (Class II design and cost estimate[b])
4	Detailed process design (Class III design and cost estimate[b])
5	Data base on detailed process and mechanical designs or historical data from existing plants

Any unusual restrictions on the data should be noted in the footnotes.

---

[a] If complete design and cost estimating methods and assumptions are not available, the rating is reduced by one unit.

[b] See Table 3-3 in Chapter 3 for definitions.

App B.4.8 Generation Data Sheet Definitions

The following material briefly defines the generation data entry items in Exhibits App B4-4 through App B4-26.

Region

This entry gives the geographic region and in some cases the specific fuel type for which the data was developed. East/West Central means both the East Central and the West Central regions.

Unit Size

The unit size is the net electrical output of the unit that forms the basis for the cost estimates.

Available for Commercial Order

If the technology is not already commercially available, this item represents the earliest date that a commercial size plant could be ordered with normal performance guarantees. This date assumes an orderly development program with success at each step. Since most technology development programs have unexpected delays and unsuccessful steps that must be repeated, the actual commercial order date is likely to be later than the one shown. Also, it should be noted that the very first commercial plants will be somewhat more expensive (in constant dollars) than the mature plant designs that form the basis for the cost estimate. Figure App B4-1 illustrates the "available for commercial order" date.

First Commercial Service

This item is an estimate of the earliest date that a commercial size plant, could be put into operation. The first commercial service date estimate is usually based on adding the idealized construction time plus an allowance for design time to the "Available for Commercial Orders" date.

Unit Capital Costs

This heading gives the basis for the cost estimate in terms of the number of units included in the plant. The various components of the Capital Cost are shown in Table 3-1 in Chapter 3.

Total Plant Cost

This entry gives the plant capital cost at a single point in time and does not include the time value of money during the construction period. Capital cost estimates expressed at a single point in time are often referred to as instantaneous or overnight construction.

Total Plant Investment

The total plant investment includes the cost of money (called AFDC) and escalation during the construction period and is expressed at the same point in time as the Total Plant Cost. The calculation procedure includes de-escalating the total plant cost back to the hypothetical beginning of construction.

An example of the calculation is given in Sample Calculation #IV in Chapter B-5 of the Background Section. For cases where the expenditure rate is uniform, the Total Plant Investment (TPI) can be calculated by multiplying the Total Plant Cost (TPC) by the appropriate Adjustment Factor (AF) from the following table.

Idealized Construction Time (years)	Adjustment Factor a) AF
6	1.097
5	1.077
4	1.057
3	1.037
2	1.018
1	1.0

---

a) Based on 8.5%/yr cost escalation and 12.5%/yr AFDC rate.

From the above table,

$$TPI = TPC \times AF$$

Startup, Inventory and Land

These costs are based on representative startup, fuel inventory, and land costs as discussed in Sections 3.5.3 through 3.5.6 of Chapter 3. The amount fuel inventory is based on the expected capacity factor of the plant.

Total Capital Requirement

This item represents all capital costs that would go into the rate base on a hypothetical January 1981 in service date. Since the technology may not be available until a much later point in time, the total capital requirement should be multiplied by the appropriate cost escalation factor for a future in service date.

Operation and Maintenance Costs

The development of the operation and maintenance costs is described in Section 3.6 of Chapter 3. The costs are expressed at the same point in time as the total capital requirement and represent the costs for a normal year of operation. The extra cost associated with the plant startup in the first year are included in the total capital requirement discussed above.

The incremental costs are broken down into variable and consumable components. The consumables such as water, limestone, are computed directly from the plant material balance. The variable component primarily represents variable maintenance and is estimated from an algorithm incorporating the expected capacity factor of the plant.

Net Heat Rate

The heat rate is based on the higher heating value (or gross heating value) of the fuel. The part load heat rate is an estimate of the actual heat rate at part load and is not an incremental heat rate.

Unit Availability

The availability definitions are given in Chapter 4. The availability estimates are based on mature plants and are likely to be significantly more optimistic than the initial experience with first of a kind plants.

Duty Cycle

Based on the plants cost and operational characteristics, the most probable duty cycle is shown. The duty cycle definitions are further discussed in Section 2.2 of Chapter 2.

Minimum Load

An estimate of the minimum load from which the plant could be ramped up to full load in a reasonable time (1 hr or less) is given.

Preconstruction, Licensing and Design Time

The time period for the preconstruction activities is very dependent on local regulations and conditions. The time period shown is intended to be a reasonable approximation. Actual times may range from one-half to two times the value shown.

Idealized Construction Time

The construction time shown is intended to be representative of the minimum construction time required to build the plant under ideal conditions. Actual construction times will likely be somewhat longer due to strikes, weather, regulatory problems, etc.

Unit Life

Unit life is an estimate of the book life of the plant. The maintenance costs include sufficient funds to replace minor equipment that wears out before the unit life shown.

Technology Development Rating and Design and Cost Estimates Rating

The rating system was designed to give an indication of the quality of the information used to develop the data (1 is poor, 5 is very good). The rating definitions are given in Section App B.4.7 of Appendix B.

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Exhibit App B4-1a

REGIONAL COAL POWER PLANT CHARACTERISTICS-LARGE UNIT SIZE
(2 Unit Plant, Supercritical, 1000 MW Unit Size)

Region (Coal Type)	Total Capital[a] Requirement Jan. 1981 in Service $/kW	Operation and Maintenance (Dec. 1980$)			Net Heat Rate Btu/kWh		Sulfur Removal %
		Fixed $/kW-yr	Variable mills/kWh	Consumable[b] mills/kWh	Full Load	Average Annual	
Northeast (Bituminous)	960	13.9	1.2	2.5	9400	9675	90
Southeast (Bituminous)	850	12.4	1.1	2.2	9380	9660	89
East Central (Bituminous)	915	12.4	1.1	3.1	9450	9735	90
West Central							
(Bituminous)	915	12.4	1.1	3.1	9450	9735	90
(Subituminous)	900	10.4	0.9	1.0	9650	9940	70
South Central (Lignite)	950	11.0	1.0	1.6	9720	10020	78
West (Bituminous)	1020	11.8	1.0	1.4	9310	9590	70

---

[a] Supercritical (3600 psi) steam conditions, plants meet 1979 Federal New Source Performance Standards

[b] Limestone, water, ash and sludge disposal

Exhibit App B4-1b

REGIONAL COAL POWER PLANT CHARACTERISTICS-INTERMEDIATE UNIT SIZE
(2 Unit Plant, Subcritical, 500 MW Unit Size)

Region (Coal Type)	Total Capital[a] Requirement Jan. 1981 in Service $/kW	Operation and Maintenance (Dec. 1980$) Fixed $/kW-yr	Variable mills/kWh	Consumable[b] mills/kWh	Net Heat Rate Btu/kWh Full Load	Average Annual	Sulfur Removal %
Northeast (Bituminous)	1045	16.1	1.1	2.6	9760	10060	90
Southeast (Bituminous)	920	14.2	1.0	2.2	9750	10040	89
East Central (Bituminous)	995	15.3	1.2	3.3	9860	10150	90
West Central							
(Bituminous)	995	15.3	1.2	3.3	9860	10150	90
(Subituminous)	990	12.3	0.9	1.1	10030	10330	70
South Central (Lignite)	1020	13.4	1.0	1.8	10110	10410	78
West (Bituminous)	1100	14.5	1.0	1.4	9680	9970	70

---

[a] Subcritical (2400 psi) steam conditions, plants meet 1979 Federal New Source Performance Standards

[b] Limestone, water, ash and sludge disposal

Exhibit App B4-2

REGIONAL NUCLEAR LIGHT WATER REACTOR (LWR) POWER PLANT COSTS[a,b]

(2 Unit Plants, 1000 MW Unit Size)

Region	Total Capital Requirement for January 1981 In Service ($/kW)	Operation and Maintenance Costs, Dec. 1980 Dollars	
		Fixed $/kW-yr	Incremental mills/kWh
Northeast	1140	8.8	1.7
Southeast	1070	8.3	1.6
East Central	1150	8.9	1.7
West Central	1070	8.3	1.6
South Central	1010	7.8	1.6
West	1110	8.5	1.7

---

[a] Figures do not include additional costs that may occur based on the Three Mile Island experience.

[b] Average Annual Heat Rate: 10,700 Btu/kWh

[redacted]

Exhibit App B4-3

REGIONAL, OIL-FIRED COMBINED-CYCLE POWER PLANT COSTS
(2 Unit Plants, 250 MW Unit Size)

	Distillate Oil[a]			Residual Oil[b]		
	Total Capital Requirement for Jan. 1981 In-Service $/kW	Operation & Maintenance (Dec. 1980 Dollars)		Total Capital Requirement for Jan. 1981 In-Service $/kW	Operation & Maintenance (Dec. 1980 Dollars)	
		Fixed $/kW-yr	Variable & Consumables mills/kWh		Fixed $/kW-yr	Variable & Consumable mills/kWh
Northeast	470	5.8	1.4	540	7.2	1.7
Southeast	425	5.2	1.3	490	6.5	1.6
East Central	430	5.3	1.3	495	6.6	1.6
West Central	430	5.3	1.3	495	6.6	1.6
South Central	410	5.1	1.2	470	6.3	1.5
West	415	5.1	1.2	480	6.4	1.6

---

[a] Full load heat rate: 8345 Btu/kWh
Average annual heat rate: 8600 Btu/kWh

[b] Full load heat rate: 8430 Btu/kWh
Average annual heat rate: 8685 Btu/kWh

Exhibit App B4-4a

CONVENTIONAL COAL-STEAM WITH WET LIMESTONE FLUE GAS DESULFURIZATION

The conventional coal fired power plant cost and performance data are based on two common types of plant: (1) a subcritical plant with a 2400 psi steam system that is capable of cycling type of operation with minimum loss of efficiency, and (2) a supercritical plant with a 3500 psi steam system that has maximum efficiency at full load. Both plants have 1000°F initial steam temperature with a singe reheat to 1000°F. The limestone flue gas desulfurization system for both plants includes four 33-1/3% capacity modules with bypasses for on-line maintenance.

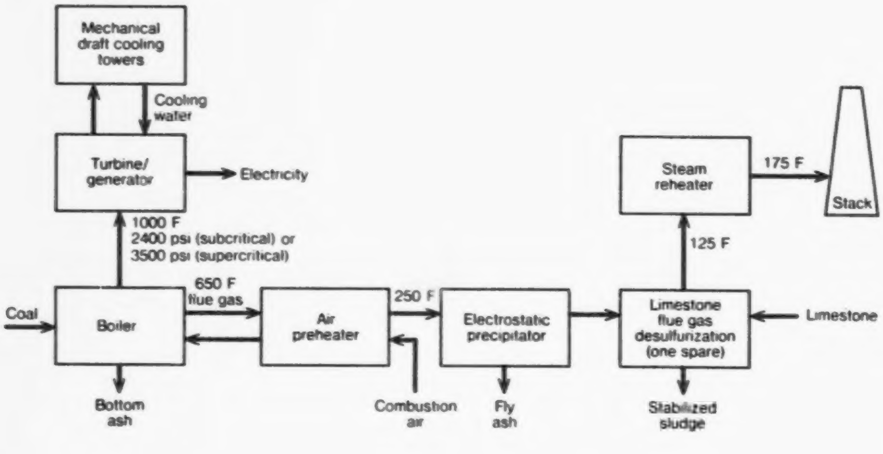

Mechanical draft cooling towers
Cooling water
Turbine/ generator
Electricity
1000 F
2400 psi (subcritical) or
3500 psi (supercritical)
Coal
Boiler
650 F flue gas
Bottom ash
Air preheater
250 F
Combustion air
Electrostatic precipitator
Fly ash
Limestone flue gas desulfurization (one spare)
Limestone
Stabilized sludge
125 F
Steam reheater
175 F
Stack

Exhibit App B4-4b
CONVENTIONAL COAL STEAM WITH WET LIMESTONE FGD[d]

Region: East/West Central (Bituminous Coal)

	Subcritical[c]	Supercritical	
Unit Size--Net Electrical Output, MW	500	500	1000
Available for Commercial Orders, Year	Current	Current	Current
First Commercial Service, Year	Current	Current	Current
Unit Capital Costs[a],$/kW (net) based on Plant Size of (number of units x unit size)	2 x 500	2 x 500	2 x 1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	885	890	795
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	935	940	855
Startup, Inventory, Land, Dec 1980 $	60	60	60
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	995	1000	915
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $			
Fixed, $/kW-yr	15.3	15.3	12.4
Incremental, mills/kWh:			
Variable	1.2	1.1	1.1
Consumable	3.3	3.1	3.1
Net Heat Rate, Btu/kWh			
Full Load	9860	9450	9450
75% Load	9950	9685	9685
50% Load	10450	10300	10300
25% Load	12575	12200	12200
Average Annual	10150	9735	9735
Unit Availability[a]			
Planned Outage Rate, %	9.6	9.6	11.0
Unplanned Outage Rage,%	16.3	16.3	18.1
Equivalent Unplanned Outage Rate, %	17.9	17.9	20.3
Operating Availability, %	75.7	75.7	72.9
Equivalent Availability, %	74.3	74.3	71.0
Average Daily Unavailability, ADU, %	1.8	1.8	2.6
Capability Ratio	1.28	1.28	1.41
Duty Cycle	Base/ Intermediate	Base	Base
Minimum Load, %	25	25	25
Preconstruction, Licensing & Design Time, Years	4	4	4
Idealized Construction Time, Years	4	4	5
Unit Life, Years	30	30	30
Technology Development Rating	5	5	5
Design & Cost Estimate Rating	3	3	3

---

[a] For mature plant.

[b] See Section App B.4.8 for definition.

[c] Suitable for cycling service (minimum load at night and weekend shutdowns).

[d] Reference Report: Coal-Fired Power Plant Capital Cost Estimates, EPRI PE-1865, May 1981.

BEST DOCUMENT AVAILABLE

Exhibit App B4-5a

CONVENTIONAL COAL-STEAM WITH REGENERATIVE FLUE GAS DESULFURIZATION

The regenerative flue gas desulfurization system cost and performance data are presented for a reference power plant with subcritical (2400 psi, 1000°F) steam system and single reheat (1000°F). The SO_2 in the flue gas is removed in an absorber with a clear solution of sodium sulfite (Wellman-Lord) or sodium citrate (advanced). The SO_2 is removed from the solution in an evaporator (Wellman-Lord) or in a steam-stripping column (advanced). The concentrated SO_2 stream is then converted to elemental sulfur by reduction with natural gas (Allied Chemical) or with anthracite coal (RESOX process). The designs are based on four 33 1/2% capacity modules with bypasses for on-line maintenance.

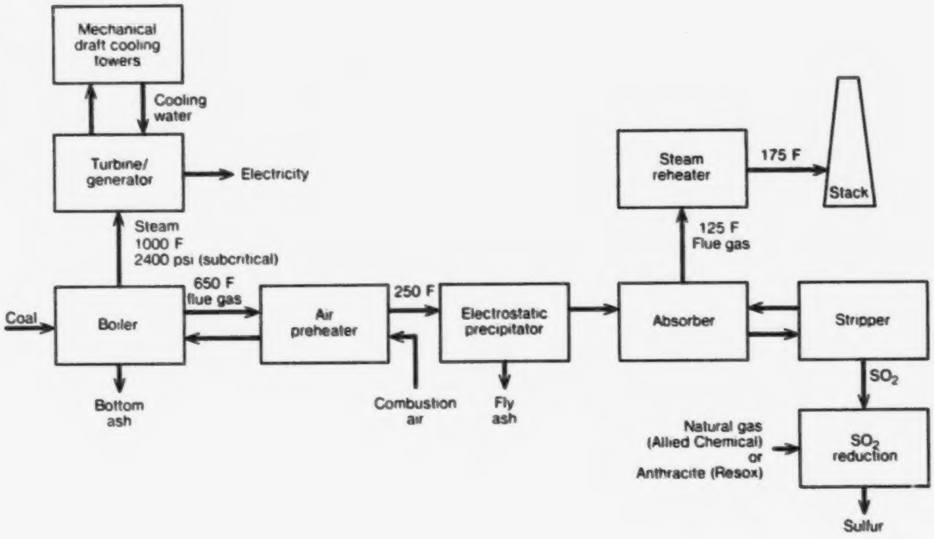

Mechanical draft cooling towers
Cooling water
Turbine/ generator
Electricity
Steam 1000 F 2400 psi (subcritical)
Coal
Boiler
650 F flue gas
Air preheater
250 F
Electrostatic precipitator
Absorber
Stripper
Bottom ash
Combustion air
Fly ash
125 F Flue gas
Steam reheater
175 F
Stack
SO₂
Natural gas (Allied Chemical) or Anthracite (Resox)
SO₂ reduction
Sulfur

Exhibit App B4-5b

CONVENTIONAL COAL-STEAM WITH REGENERATIVE FGD[d]

Region: East/West Central (Bituminous Coal)

	FGD Current	FGD Advanced
Unit Size--Net Electrical Output, MW	500	500
Available for Commercial Orders, Year	Current	1984[c]
First Commercial Service, Year	Current	1987
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	2 x 500	2 x 500
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	945	990
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1000	1045
Startup, Inventory, Land, Dec 1980 $	65	65
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1065	1110
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	16.4	16.5
Incremental, mills/kWh:		
Variable	1.2	1.2
Consumable	2.6[e]	1.8
Net Heat Rate, Btu/kWh		
Full Load	10290	10385
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	10600	10700
Unit Availability[a]		
Planned Outage Rate, %	9.6	9.6
Unplanned Outage Rage, %	16.3	16.3
Equivalent Unplanned Outage Rate, %	16.4	16.4
Operating Availability, % 75.7	75.7	
Equivalent Availability, %	75.6	75.6
Average Daily Unavailability, ADU, %	0.2	0.2
Capability Ratio	1.25	1.25
Duty Cycle	Base	Base
Minimum Load, %	25	25
Preconstruction, Licensing & Design Time, Years	4	4
Idealized Construction Time, Years	4	4
Unit Life, Years	30	30
Technology Development Rating	4	3
Design & Cost Estimate Rating	3	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Order applied to FGD system only

[d] Reference Reports: Coal-Fired Power Plant Capital Cost Estimates, EPRI PE-1865 May 1981. Economic and Design Factors for Flue Gas Desulfurization Technology, EPRI CS-1428, April 1980.

[e] Includes 210 Btu/KWh of natural gas for SO_2 reduction to elemental sulfur.

Exhibit App B4-6a

ADVANCED PULVERIZED COAL-STEAM, CHYODA THOROUGHBRED 121 FLUE GAS DESULFURIZATION

The advanced pulverized coal-fired power plant represents an evolutionary extension of current technology to higher levels of thermal efficiency. The boiler and turbine are designed for sliding pressure operation with maximum steam conditions of 4500 psi pressure, initial temperature of 1100°F and two reheats to 1050°F. The advanced limestone based flue gas desulfurization (FGD) system produces gypsum. The FGD system includes four 33 1/3% capacity modules with bypasses for on-line maintenance.

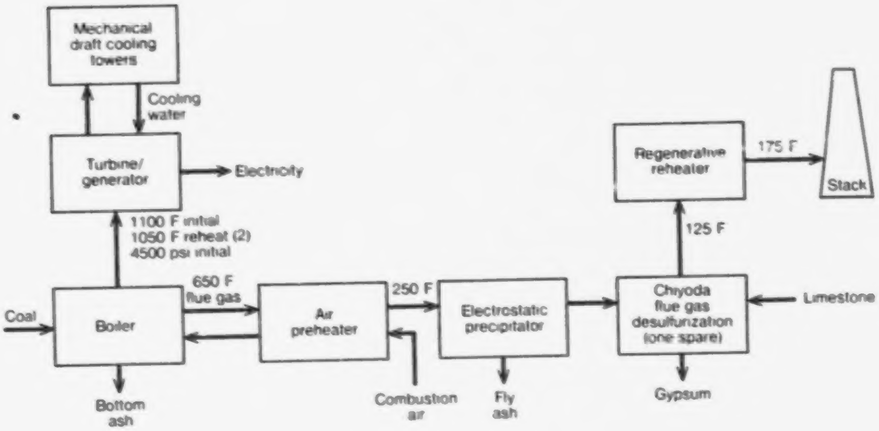

Mechanical draft cooling towers
Cooling water
Turbine/ generator
Electricity
1100 F initial
1050 F reheat (2)
4500 psi initial
Coal
Boiler
650 F flue gas
Bottom ash
Air preheater
250 F
Combustion air
Electrostatic precipitator
Fly ash
Chiyoda flue gas desulfurization (one spare)
Limestone
Gypsum
125 F
Regenerative reheater
175 F
Stack

Exhibit App B4-6b

ADVANCED PULVERIZED COAL-STEAM, CHIYODA FGD[c]

Region: East/West Central (Bituminous Coal)

Unit Size--Net Electrical Output, MW	750
Available for Commercial Orders, Year	1985
First Commercial Service, Year	1992
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	1 x 750
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	975
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1045
Startup, Inventory, Land, Dec 1980 $	60
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1105
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	14.7
Incremental, mills/kWh:	
Variable	0.8
Consumable	1.6
Net Heat Rate, Btu/kWh	
Full Load	8420
75% Load	-
50% Load	-
25% Load	-
Average Annual	8670
Unit Availability[a]	
Planned Outage Rate, %	-
Unplanned Outage Rage, %	-
Equivalent Unplanned Outage Rate, %	-
Operating Availability, %	-
Equivalent Availability, %	-
Average Daily Unavailability, ADU, %	-
Capability Ratio	-
Duty Cycle	Base
Minimum Load, %	30
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	5
Unit Life, Years	30
Technology Development Rating	4
Design & Cost Estimate Rating	2

---

[a] For mature plant

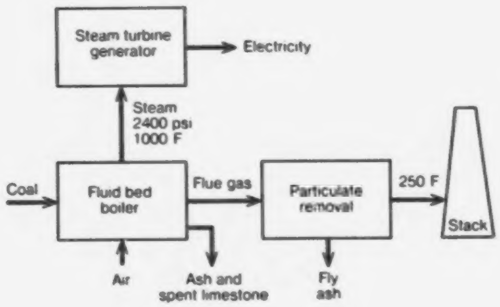
[b] See Section App B.4.8 for definition.

[c] Reference Report, Engineering Assessment of A Low Heat Rate Pulverized Coal Power Plant, EPRI RP1403-1, In Publication.

Exhibit App B4-7a

ATMOSPHERIC FLUID BED COMBUSTION

Crushed coal is burned with limestone in an atmospheric pressurized fluid bed suspended by air blown in from below. The calcium in the limestone captures most of the sulfur released from the coal during combustion. Particulates are captured in a series of cyclones followed by an electrostatic precipitator. Steam is produced inside tubes passing through the bed and/or through the hot gas stream. The steam is used to drive a conventional steam turbine generator.


Steam turbine generator
Electricity
Steam
2400 psi
1000 F
Coal
Fluid bed boiler
Flue gas
Particulate removal
250 F
Stack
Air
Ash and spent limestone
Fly ash

[redacted]

Exhibit App B4-7b
ATMOSPHERIC FLUID BED COMBUSTION[c]

Region: East/West Central

	Fuel	
	Bituminous	Subbituminous
Unit Size--Net Electrical Output, MW	500	500
Available for Commercial Orders, Year	1986	1986
First Commercial Service, Year	1993	1993
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 500	2 x 500
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	725	700
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	765	735
Startup, Inventory, Land, Dec 1980 $	55	50
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	820	785
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	8.4	8.4
Incremental, mills/kWh:		
Variable	0.8	0.8
Consumable	3.5	0.8
Net Heat Rate, Btu/kWh		
Full Load	9640	9840
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	9930	10130
Unit Availability[a]		
Planned Outage Rate, %	9.6	9.6
Unplanned Outage Rage, %	7.2	7.2
Equivalent Unplanned Outage Rate, %	16.5	16.5
Operating Availability, %	83.9	83.9
Equivalent Availability, %	75.5	75.5
Average Daily Unavailability, ADU, %	10	10
Capability Ratio	1.23	1.23
Duty Cycle	Base	Base
Minimum Load, %	35	35
Preconstruction, Licensing & Design Time, Years	4	4
Idealized Construction Time, Years	4	4
Unit Life, Years	30	30
Technology Development Rating	3	3
Design & Cost Estimate Rating	3	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Reference Report: Assessment of Atmospheric Fluid Bed Recycle Systems, EPRI RP1180-1, In Publication.

[redacted]

Exhibit App B4-8a

PRESSURIZED FLUID BED COMBUSTION-COMBINED CYCLE

Crushed coal is burned with dolomite in a pressurized fluid bed suspended by air blown in from below. The pressure in the combustion chamber is at a level of six to sixteen times atmospheric pressure. Calcium in the dolomite captures most of the sulfur released from the coal during combustion. The hot pressurized gases leaving the combustor pass through a filter to remove suspended particulates and then drive a gas turbine/electric generator. Steam generated in tubes in the bed and in a waste heat boiler drives a conventional steam turbine/electric generator.

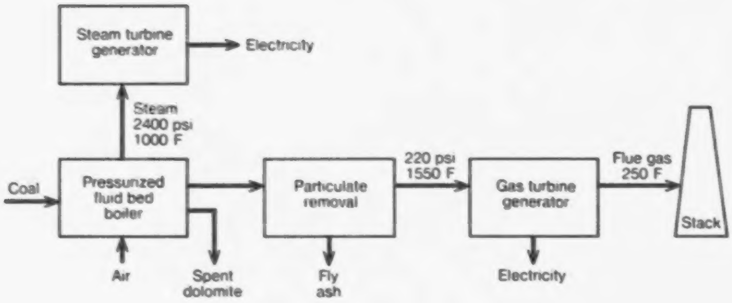

Steam turbine generator
Electricity
Steam
2400 psi
1000 F
Coal
Pressurized fluid bed boiler
Particulate removal
220 psi
1550 F
Gas turbine generator
Flue gas
250 F
Stack
Air
Spent dolomite
Fly ash
Electricity

Exhibit App B4-8b

PRESSURIZED FLUID BED COMBUSTION-COMBINED CYCLE[c]

Region: East/West Central (Bituminous Coal)

Unit Size--Net Electrical Output, MW	650
Available for Commercial Orders, Year	1989
First Commercial Service, Year	1995
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	2 x 650
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	780
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	825
Startup, Inventory, Land, Dec 1980 $	50
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	875
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	11.4
Incremental, mills/kWh:	
Variable	0.8
Consumable	3.1
Net Heat Rate, Btu/kWh	
Full Load	8470
75% Load	-
50% Load	-
25% Load	-
Average Annual	8720
Unit Availability[a]	
Planned Outage Rate, %	9.6
Unplanned Outage Rage, %	2.2
Equivalent Unplanned Outage Rate, %	14.9
Operating Availability, %	88.4
Equivalent Availability, %	76.9
Average Daily Unavailability, ADU, %	13
Capability Ratio	1.19
Duty Cycle	Base
Minimum Load, %	35
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	4
Unit Life, Years	30
Technology Development Rating	2
Design & Cost Estimate Rating	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Reference Report: Preliminary Assessment of Alternative PFBC Power Plant Systems, EPRI CS-1451, July 1980.

[redacted]

Exhibit App B4-9a

GASIFICATION-COMBINED CYCLE - TEXACO GASIFIER

Pulverized coal in a concentrated water slurry is pumped into an entrained flow gasifier where a partial oxidation process using oxygen produces an intermediate Btu gas (Ca 300 Btu/SCF). After the gas passes through a heat recovery section, the sulfur and nitrogen compounds and particulates are removed, and the clean gas is fired in a combustion turbine (at 2000°F for current turbines and 2600°F for advanced turbines). The hot exhaust gases generate steam in heat recovery boilers. The steam is used to drive both a steam turbine generator and steam turbine compressors in the oxygen plant. The sulfur compounds are reduced to elemental sulfur in a Claus plant.

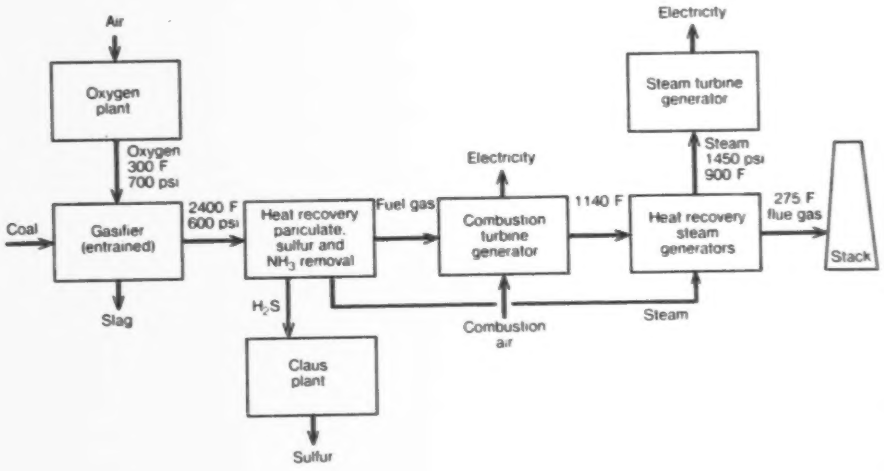

Air
Oxygen plant
Oxygen
300 F
700 psi
Coal
Gasifier (entrained)
Slag
2400 F
600 psi
Heat recovery particulate, sulfur and NH_3 removal
H_2S
Claus plant
Sulfur
Fuel gas
Electricity
Combustion turbine generator
Combustion air
1140 F
Electricity
Steam turbine generator
Steam
1450 psi
900 F
Heat recovery steam generators
Steam
275 F
flue gas
Stack

Exhibit App B4-9b

GASIFICATION-COMBINED CYCLE-TEXACO GASIFIER[d]

Region: East/West Central (Bituminous Coal)

	Combustion Turbine Design	
	Current	Advanced
Unit Size--Net Electrical Output, MW	1000	1000
Available for Commercial Orders, Year	1986	1995
First Commercial Service, Year	1991	2000
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	1 x 1000	1 x 1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	940	880
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	975	915
Startup, Inventory, Land, Dec 1980 $	55	50
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1030	965
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	17.9	25.7
Incremental, mills/kWh:		
Variable	1.2	1.8
Consumable	1.0	0.5
Net Heat Rate, Btu/kWh		
Full Load	9460	8465
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	9740	8720
Unit Availability[a]		
Planned Outage Rate, %	11	11
Unplanned Outage Rage, %	-[c]	-[c]
Equivalent Unplanned Outage Rate, %	8.9	11.4
Operating Availability, %	89	89
Equivalent Availability, %	81.1	78.9
Average Daily Unavailability, ADU, %	8.8	11.4
Capability Ratio	1.13	1.14
Duty Cycle	Base	Base
Minimum Load, %	40	-
Preconstruction, Licensing & Design Time, Years	4	4
Idealized Construction Time, Years	3	3
Unit Life, Years	30	30
Technology Development Rating	3	2
Design & Cost Estimate Rating	3	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Modularity and steam generator bypass make full outages unlikely.

[d] Reference Reports: Economics of Oxygen Blown Texaco GCC Plants, EPRI AP1624, Nov. 1980 Gasification - Fuel Cell and Gas Turbine Power Plants, EPRI AP-1543, Sept. 1980.

[redacted]

Exhibit App B4-10a

GASIFICATION-COMBINED CYCLE -
BRITISH GAS COUNCIL SLAGGING GASIFIER

Sized coal (1½" x 0") is fed to a moving bed gasifier where devolatilization and partial oxidation reactions using oxygen and steam take place to produce a raw gas containing some heavy tars. The tars are removed and recycled to the gasifier. Sulfur and nitrogen compounds are removed and the clean fuel gas is fired in an advanced (2600°F) combustion turbine generator. The hot exhaust gases generate steam in heat recovery boilers. The steam is used to drive both steam turbine generator and steam turbine compressors in the oxygen plant. The sulfur compounds are reduced to elemental sulfur in a Claus plant.

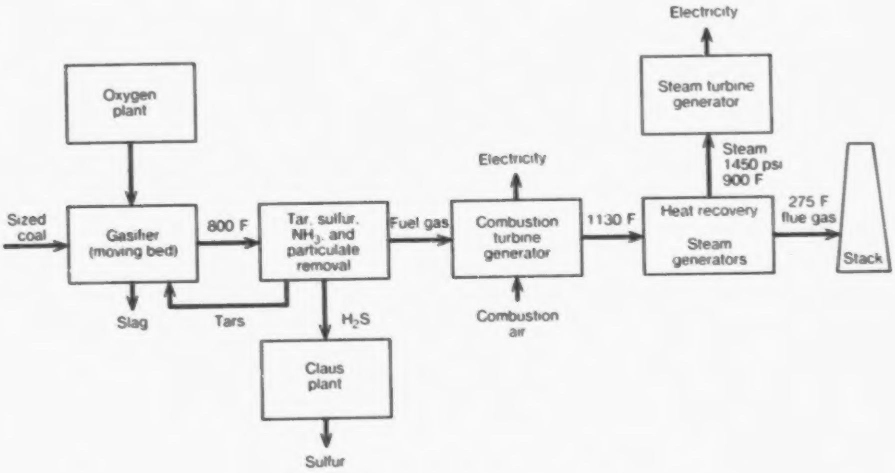

Electricity
Steam turbine generator
Oxygen plant
Steam 1450 psi 900 F
Electricity
Sized coal
Gasifier (moving bed)
800 F
Tar, sulfur, NH_3, and particulate removal
Fuel gas
Combustion turbine generator
1130 F
Heat recovery
Steam generators
275 F flue gas
Stack
Slag
Tars
H_2S
Combustion air
Claus plant
Sulfur

Exhibit App B4-10b

GASIFICATION-COMBINED CYCLE-BRITISH GAS COUNCIL (BGC) SLAGGING GASIFIER[d]

Region: East/West Central (Bituminous Coal)

	Advanced Combustion Turbine
Unit Size--Net Electrical Output, MW	1000
Available for Commercial Orders, Year	1995
First Commercial-Service, Year	2000
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	1 x 1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	730
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	760
Startup, Inventory, Land, Dec 1980 $	45
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	805
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	23.9
Incremental, mills/kWh:	
Variable	1.7
Consumable	0.5
Net Heat Rate, Btu/kWh	
Full Load	7920
75% Load	-
50% Load	-
25% Load	-
Average Annual	8155
Unit Availability[a]	
Planned Outage Rate, %	11
Unplanned Outage Rage, %	-[c]
Equivalent Unplanned Outage Rate, %	10.8
Operating Availability, %	89.0
Equivalent Availability, %	79.4
Average Daily Unavailability, ADU, %	10.8
Capability Ratio	1.13
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	3
Unit Life, Years	30
Technology Development Rating	2
Design & Cost Estimate Rating	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Modularity and steam generator bypass make full outages unlikely

[d] Reference Report: Gasification-Fuel Cell and Gas Turbine Power Plants, EPRI AP 1543, Sept 1980.

[redacted]

Exhibit App B4-11a

GASIFICATION-FUEL CELL COMBINED CYCLE-TEXACO GASIFIER

Pulverized coal in a concentrated water slurry is pumped into an entrained flow gasifier where a partial oxidation process using oxygen produces an intermediate Btu gas. The gas passes through a heat recovery section followed by a clean-up section where sulfur and nitrogen compounds and particulates are removed. The clean gas then enters the anode of the molten carbonate fuel cell. Hot exhaust gas from the fuel cell is used to generate steam in heat recovery boilers. The steam is used to drive both a steam turbine generator and steam turbine compressors in the oxygen plant. The sulfur compounds are reduced to elemental sulfur in a Claus plant.

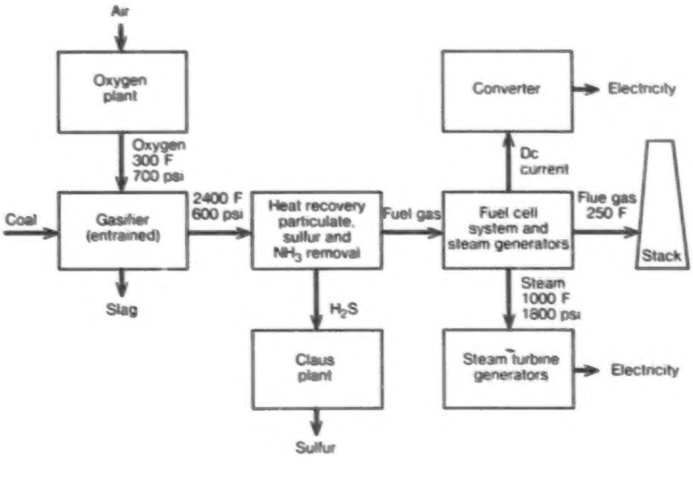

Air
Oxygen plant
Oxygen
300 F
700 psi
Coal
Gasifier (entrained)
Slag
2400 F
600 psi
Heat recovery particulate, sulfur and NH_3 removal
H_2S
Claus plant
Sulfur
Fuel gas
Fuel cell system and steam generators
Dc current
Converter
Electricity
Flue gas
250 F
Stack
Steam
1000 F
1800 psi
Steam turbine generators
Electricity

Exhibit App B4-11b

GASIFICATION-FUEL CELL COMBINED CYCLE-TEXACO GASIFIER[d]

Region: East/West Central (Bituminous Coal)

	Molten Carbonate Fuel Cell
Unit Size--Net Electrical Output, MW	1500
Available for Commercial Orders, Year	1990
First Commercial Service, Year	1995
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 1500
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	920
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	950
Startup, Inventory, Land, Dec 1980 $	45
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	995
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	16.6
Incremental, mills/kWh:	
Variable	1.0
Consumable	0.5
Fuel Cell replacement[c]	1.6
Net Heat Rate, Btu/kWh	
Full Load	7130
75% Load	6900
50% Load	6900
25% Load	-
Average Annual	7130
Unit Availability[a]	
Planned Outage Rate, %	12.4
Unplanned Outage Rage, %	-[d]
Equivalent Unplanned Outage Rate, %	10.5
Operating Availability, %	87.6
Equivalent Availability, %	78.4
Average Daily Unavailability, ADU, %	10.5
Capability Ratio	1.14
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	3
Unit Life, Years	30
Technology Development Rating	2
Design & Cost Estimate Rating	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition

[c] For Fuel Cell replacement treated as an expense

[d] Modularity and bypass systems make a full outage unlikely

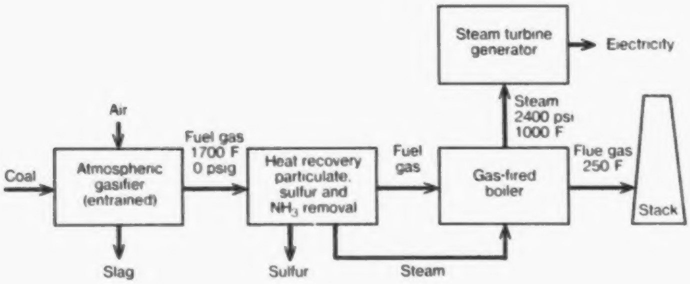
[e] Reference Report: Gasification-Fuel Cell and Gas Turbine Power Plants, EPRI AP1453, Sept. 1980.

[redacted]

Exhibit App B4-12a

GASIFIER-GAS FIRED BOILER COMBUSTION ENGINEERING GASIFIER

Pulverized coal is gasified by partial oxidation with air in a two-stage entrained system operated at atmospheric pressure. The low Btu gas (Ca 100 Btu/SCF) is processed to remove particulates and sulfur compounds and fired directly in a steam boiler. The heat recovery system in the gasification section is integrated with the steam boiler to maximize the system efficiency.


Steam turbine generator
Electricity
Air
Steam 2400 psi 1000 F
Fuel gas 1700 F 0 psig
Fuel gas
Flue gas 250 F
Coal
Atmospheric gasifier (entrained)
Heat recovery particulate, sulfur and NH_3 removal
Gas-fired boiler
Stack
Slag
Sulfur
Steam

[redacted]

Exhibit App B4-12b

GASIFIER-GAS FIRED BOILER-COMBUSTION ENGINEERING GASIFIER

Region: East/West Central (Bituminous Coal)

Unit Size--Net Electrical Output, MW	1000
Available for Commercial Orders, Year	1987
First Commercial Service, Year	1993
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	985
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1045
Startup, Inventory, Land, Dec 1980 $	50
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1095
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	30.8
Incremental, mills/kWh:	
Variable	2.2
Consumable	0.7
Net Heat Rate, Btu/kWh	
Full Load	9665
75% Load	-
50% Load	-
25% Load	-
Average Annual	9955
Unit Availability[a]	
Planned Outage Rate, %	11
Unplanned Outage Rage, %	10.9
Equivalent Unplanned Outage Rate, %	15.3
Operating Availability, %	79.3
Equivalent Availability, %	75.4
Average Daily Unavailability, ADU, %	5
Capability Ratio	1.27
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	4
Unit Life, Years	30
Technology Development Rating	3
Design & Cost Estimate Rating	2

---

[a] For mature plant

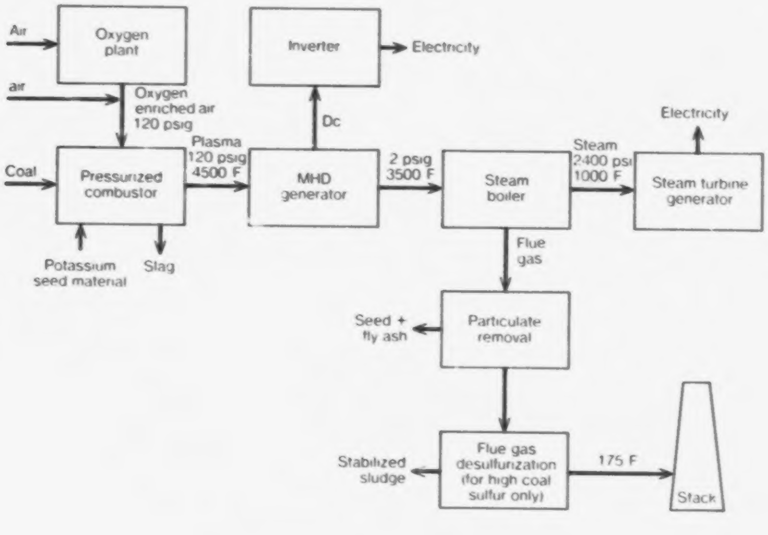
[b] See Section App B.4.8 for definition.

[redacted]

Exhibit App B4-13a

MAGNETOHYDRODYNANIC (MHD) - COMBINED CYCLE

Pulverized coal is combusted at about 8 atmospheres pressure with oxygen enriched air to produce a 4500°F plasma which passes through an MHD generator. The hot exhaust gases from the MHD generator are cooled in a boiler that generates steam for a conventional steam turbine/electric generator. Particulate matter is removed from the flue gases by an electrostatic precipitator. Sulfur compounds are removed from the flue gas by either reaction with the potassium seed material or by a conventional limestone flue gas desulfurization unit. Cost data are based on the plant configuration that is judged closest to commercial practice. More advanced configurations with potentially lower cost and higher efficiency are discussed in the referenced report (EPRI AP 1316).


Air
Oxygen plant
air
Oxygen enriched air 120 psig
Coal
Pressurized combustor
Potassium seed material
Slag
Plasma 120 psig 4500 F
Inverter
Electricity
Dc
MHD generator
2 psig 3500 F
Steam boiler
Steam 2400 psi 1000 F
Electricity
Steam turbine generator
Flue gas
Seed + fly ash
Particulate removal
Stabilized sludge
Flue gas desulfurization (for high coal sulfur only)
175 F
Stack

[redacted]

Exhibit App B4-13b

MAGNETOHYDRODYNAMIC (MHD) - COMBINED CYCLE[c]

Region: West Central (Subbituminous Coal)

Unit Size--Net Electrical Output, MW	1000
Available for Commercial Orders, Year	1995
First Commercial Service, Year	2003
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1x1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	1175
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1295
Startup, Inventory, Land, Dec 1980 $	65
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1360
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	12.9
Incremental, mills/kWh:	
Variable	0.9
Consumable	0.9
Net Heat Rate, Btu/kWh	
Full Load	9050
75% Load	-
50% Load	-
25% Load	-
Average Annual	9320
Unit Availability[a]	
Planned Outage Rate, %	11.9
Unplanned Outage Rage, %	23.4
Equivalent Unplanned Outage Rate, %	28.3
Operating Availability, %	67.5
Equivalent Availability, %	63.2
Average Daily Unavailability, ADU, %	6.4
Capability Ratio	1.61
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	6
Unit Life, Years	30
Technology Development Rating	2
Design & Cost Estimate Rating	2

---

[a] For mature plant

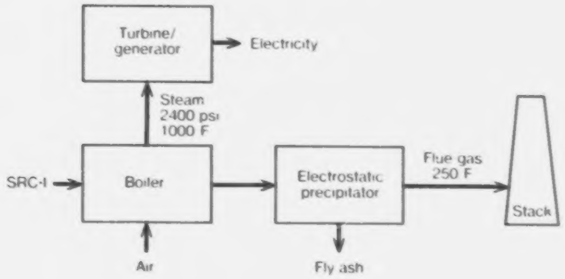
[b] See Section App B.4.8 for definition.

[c] Reference Report: Open Cycle MHD Systems Analysis, EPRI AP-1316 February 1980.

Exhibit App B4-14a

SOLID SOLVENT REFINED COAL-STEAM POWER PLANT

Solid solvent refined coal (SRC-I) is a low sulfur, low ash solid fuel that can be pulverized and fired in a boiler that is very similar to a conventional coal-fired boiler/steam turbine generator with single reheat. The particulate matter is removed from the flue gas with a conventional electrostatic precipitator.


Turbine/
generator
Electricity
Steam
2400 psi
1000 F
SRC-I
Boiler
Air
Electrostatic
precipitator
Fly ash
Flue gas
250 F
Stack

[redacted]

Exhibit App B4-14b

SOLID SOLVENT REFINED COAL-STEAM POWER PLANT[c]

Region: East/West Central

	SRC-I
Unit Size--Net Electrical Output, MW	500
Available for Commercial Orders, Year	1984
First Commercial Service, Year	1991
Unit Capital Costs[a], \$/kW (net) based on Plant Size of (number of units x unit size)	2 x 500
Total Plant Cost, Dec 1980 \$ (based on overnight construction)[b]	740
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	785
Startup, Inventory, Land, Dec 1980 \$	60
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	845
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 \$	
Fixed, \$/kW-yr	3.4
Incremental, mills/kWh:	
Variable	2.9
Consumable	0.3
Net Heat Rate, Btu/kWh	
Full Load	9400
75% Load	9440
50% Load	-
25% Load	-
Average Annual	9700
Unit Availability[a]	
Planned Outage Rate, %	9.6
Unplanned Outage Rage, %	11.3
Equivalent Unplanned Outage Rate, %	11.3
Operating Availability, %	80.2
Equivalent Availability, %	80.2
Average Daily Unavailability, ADU, %	-
Capability Ratio	1.17
Duty Cycle	Intermediate
Minimum Load, %	25
Preconstruction, Licensing & Design Time, Years	3
Idealized Construction Time, Years	4
Unit Life, Years	30
Technology Development Rating	4
Design & Cost Estimate Rating	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Reference Report: Capital Costs of SRC-Fired Power Plants, EPRI AF-1011, February 1979.

[redacted]

Exhibit App B4-15a

LIQUID FUEL STEAM POWER PLANT

The liquid fuel steam plant is based on conventional technology. The low sulfur fuel is burned in a boiler to generate 2400 psi, 1000°F steam (with single reheat to 1000°F) that drives a conventional steam turbine/electric generator. For distillate fuel, the flue gas is sent directly to the stack. With residual or ash bearing fuels, an electrostatic precipitator is included to remove particulates from the flue gas.

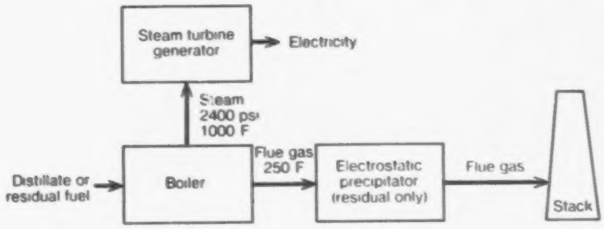

Steam turbine generator
Electricity
Steam 2400 psi 1000 F
Distillate or residual fuel
Boiler
Flue gas 250 F
Electrostatic precipitator (residual only)
Flue gas
Stack

Exhibit App B4-15b

LIQUID FUEL FIRED STEAM POWER PLANT[c]

Region: East/West Central

	Fuel	
	Distillate	Residual
Unit Size--Net Electrical Output, MW	500	500
Available for Commercial Orders, Year	Current	Current
First Commercial Service, Year	Current	Current
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 500	2 x 500
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	485	560
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	510	595
Startup, Inventory, Land, Dec 1980 $	60	55
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	570	650
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	1.7	1.7
Incremental, mills/kWh:		
Variable	1.3	1.3
Consumable	0.3	0.3
Net Heat Rate, Btu/kWh		
Full Load	9400	9400
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	9680	9680
Unit Availability[a]		
Planned Outage Rate, %	9.6	9.6
Unplanned Outage Rage, %	11.3	11.3
Equivalent Unplanned Outage Rate, %	11.3	11.3
Operating Availability, %	80.2	80.2
Equivalent Availability, %	80.2	80.2
Average Daily Unavailability, ADU, %	-	-
Capability Ratio	1.17	1.17
Duty Cycle	Intermediate	Intermediate
Minimum Load, %	25	25
Preconstruction, Licensing & Design Time, Years	3	3
Idealized Construction Time, Years	4	4
Unit Life, Years	30	30
Technology Development Rating	5	5
Design & Cost Estimate Rating	2	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Reference Report: Fossil and Nuclear Central-Station Power Plants Investment Estimates EPRI TPS 75-601, Sept 1975.

Exhibit App B4-16a

LIQUID FUELED COMBINED CYCLE - CONVENTIONAL

Low sulfur distillate or residual fuel is fired in a combustion turbine/electric generator with a nominal 1950°F turbine inlet temperature for current technology. The hot exhaust gases from the turbine pass through a heat recovery steam generator (HRSG) that produces steam for a conventional steam turbine/electric generator. A bypass around the HRSG is included for operating flexibility. The residual fuel plant includes fuel treating facilities for removing salts and other sediment.

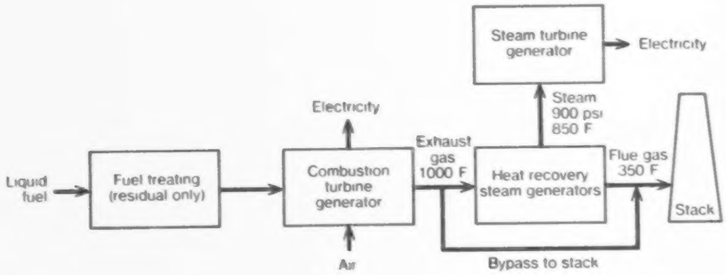

Steam turbine generator
Electricity
Electricity
Steam 900 psi 850 F
Liquid fuel
Fuel treating (residual only)
Combustion turbine generator
Exhaust gas 1000 F
Heat recovery steam generators
Flue gas 350 F
Stack
Air
Bypass to stack

Exhibit App B4-16b

LIQUID FUELED COMBINED CYCLE-CONVENTIONAL[d]

Region: East/West Central

	Fuel	
	Distillate	Residual
Unit Size--Net Electrical Output, MW	250	250
Available for Commercial Orders, Year	Current	Current
First Commercial Service, Year	Current	Current
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 250	2 x 250
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	375	445
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	380	450
Startup, Inventory, Land, Dec 1980 $	50	45
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	430	495
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	5.3	6.6
Incremental, mills/kWh:		
Variable	1.2	1.5
Consumable	0.1	0.1
Net Heat Rate, Btu/kWh		
Full Load	8345	8430
75% Load	-	-
50% Load	9180	9275
25% Load	-	-
Average Annual	8600	8685
Unit Availability[a]		
Planned Outage Rate, %	7.0	7.0
Unplanned Outage Rage, %	-[c]	-[c]
Equivalent Unplanned Outage Rate, %	7.4	9.6
Operating Availability, %	93.0	85.1
Equivalent Availability, %	92.9	84.6
Average Daily Unavailability, ADU, %	7.2	8.8
Capability Ratio	1.08	1.10
Duty Cycle	Intermediate	Intermediate
Minimum Load, %	-	-
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	2	2
Unit Life, Years	30	30
Technology Development Rating	5	4
Design & Cost Estimate Rating	3	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Modularity and bypasses make full outage unlikely

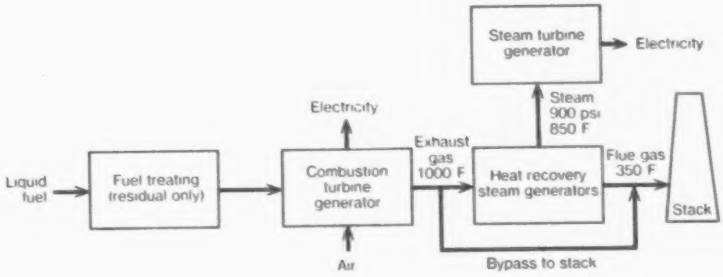
[d] Reference Report: Combined Cycle Power Plant Capital Cost Estimates, EPRI AF 610, Dec. 1977.

[redacted]

Exhibit App B4-17a

LIQUID FUELED COMBINED CYCLE - ADVANCED

Low sulfur distillate or residual fuel is fired in an advanced combustion turbine/electric generator with a nominal 2200°F turbine inlet temperature. The hot exhaust gases from the turbine pass through a heat recovery steam generator (HRSG) that produces steam for a conventional steam turbine/electric generator. A bypass around the HRSG is included for operating flexibility. The residual fuel plant includes fuel treating facilities for removing salts and other sediment.


Steam turbine generator
Electricity
Electricity
Steam
900 psi
850 F
Exhaust gas
1000 F
Flue gas
350 F
Liquid fuel
Fuel treating (residual only)
Combustion turbine generator
Heat recovery steam generators
Stack
Air
Bypass to stack

[redacted]

Exhibit B4-17b

LIQUID FUELED COMBINED CYCLE - ADVANCED

Region: East/West Central

	Fuel	
	Distillate	Residual
Unit Size--Net Electrical Output, MW	300	300
Available for Commercial Orders, Year	1986	1986
First Commercial Service, Year	1989	1989
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 300	2 x 300
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	405	475
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	410	490
Startup, Inventory, Land, Dec 1980 $	45	40
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	455	530
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	5.3	6.6
Incremental, mills/kWh:		
Variable	1.2	1.5
Consumable	0.1	0.1
Net Heat Rate, Btu/kWh		
Fuel Load		
75% Load	-	-
50% Load	-	-
25% Load	-	-
Average Annual	7520	7620
Unit Availability[a]		
Planned Outage Rate, %	7.0	7.0
Unplanned Outage Rage, %	-[c]	-[c]
Equivalent Unplanned Outage Rate, %	5.9	7.5
Operating Availability, %	93	93
Equivalent Availability, %	87.5	86
Average Daily Unavailability, ADU, %	6	7.3
Capability Ratio	1.07	1.08
Duty Cycle	Intermediate	Intermediate
Minimum Load, %	-	-
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	2	2
Unit Life, Years	30	30
Technology Development Rating	2	2
Design & Cost Estimate Rating	1	1

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

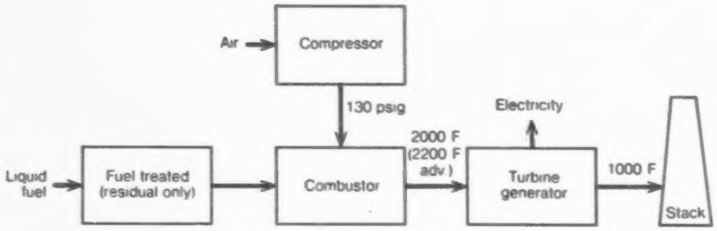
[c] Modularity and bypasses make full outages unlikely

[redacted]

Exhibit App B4-18a

LIQUID FUELED COMBUSTION TURBINE - CONVENTIONAL

Low sulfur distillate or residual fuel is fired in a combustion turbine/electric generator with a nominal 1950°F turbine inlet temperature. The residual fuel plant includes fuel treating facilities for removing salts or other sediment.


Air
Compressor
130 psig
Electricity
Liquid fuel
Fuel treated (residual only)
Combustor
2000 F (2200 F adv.)
Turbine generator
1000 F
Stack

BEST DOCUMENT AVAILABLE

Exhibit App B4-18b

LIQUID FUELED COMBUSTION TURBINE - CONVENTIONAL

Region: East/West Central

	Fuel	
	Distillate	Residual
Unit Size--Net Electrical Output, MW	75	75
Available for Commercial Orders, Year	Current	Current
First Commercial Service, Year	Current	Current
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 75	2 x 75
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	205	225
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	205	225
Startup, Inventory, Land, Dec 1980 $	10	10
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	215	235
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	0.4	0.4
Incremental, mills/kWh:		
Variable	3.2	3.7
Consumable	-	-
Net Heat Rate, Btu/kWh		
Full Load	11500	11700
75% Load	12250	12460
50% Load	14140	14390
25% Load	-	-
Average Annual	13800	14000
Unit Availability[a]		
Planned Outage Rate, %	3.2	3.2
Unplanned Outage Rage, %	8	10
Equivalent Unplanned Outage Rate, %	8	10
Operating Availability, %	89.1	87.1
Equivalent Availability, %	89.1	87.1
Average Daily Unavailability, ADU, %	-	-
Capability Ratio	1.09	1.11
Duty Cycle	Peaking	Peaking
Minimum Load, %	-	-
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	1	1
Unit Life, Years	20	20
Technology Development Rating	5	5
Design & Cost Estimate Rating	1	1

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

Exhibit App B4-19a

LIQUID FUELED COMBUSTION TURBINE - ADVANCED

Low sulfur distillate or residual fuel is fired in an advanced combustion turbine/electric generator with a nominal 2200°F turbine inlet temperature. The residual fuel plant includes fuel treating facilities for removing salts or other sediment.

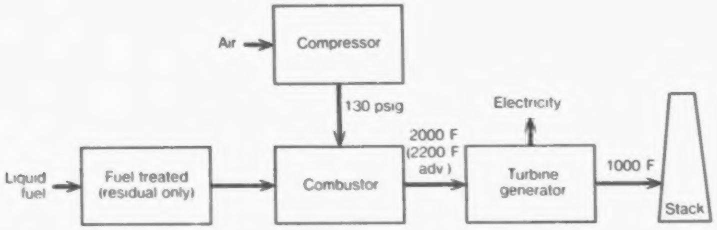

Air
Compressor
130 psig
Electricity
Liquid fuel
Fuel treated (residual only)
Combustor
2000 F (2200 F adv)
Turbine generator
1000 F
Stack

Exhibit App B4-19b

LIQUID FUELED COMBUSTION TURBINE - ADVANCED

Region: East/West Central

	Fuel	
	Distillate	Residual
Unit Size--Net Electrical Output, MW	100	100
Available for Commercial Orders, Year	1985	1985
First Commercial Service, Year	1987	1987
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 100	2 x 100
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	220	245
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	220	245
Startup, Inventory, Land, Dec 1980 $	10	10
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	230	255
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	0.4	0.4
Incremental, mills/kWh:		
Variable	3.2	3.7
Consumable	-	-
Net Heat Rate, Btu/kWh		
Full Load	10,300	10,500
75% Load	10,970	11,180
50% Load	12,670	12,910
25% Load	-	-
Average Annual	12,360	12,600
Unit Availability[a]		
Planned Outage Rate, %	3.2	3.2
Unplanned Outage Rage, %	6.0	8.0
Equivalent Unplanned Outage Rate, %	6.0	8.0
Operating Availability, %	91.0	89.1
Equivalent Availability, %	91.0	89.1
Average Daily Unavailability, ADU, %	-	-
Capability Ratio	1.07	1.09
Duty Cycle	Peaking	Peaking
Minimum Load, %	-	-
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	1	1
Unit Life, Years	20	20
Technology Development Rating	2	2
Design & Cost Estimate Rating	1	1

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

Exhibit App B4-20a

DISPERSED FUEL CELLS

Dispersed fuel cell power plants are modular units composed of three major subsystems: (1) the fuel processor, (2) the power section, and (3) the power conditioner. The fuel processor reforms the light distillate fuel or other liquid or gaseous fuel into a hydrogen-rich gas. The power section (composed of fuel cell stacks) converts the hydrogen with oxygen from ambient air into water and electricity. The power conditioner converts dc power to ac power compatible with the utility bus. The first generation fuel cells use phosphoric acid as the electrolyte. The advanced fuel cells are based on a molten carbonate electrolyte or an improved phosphoric acid version.

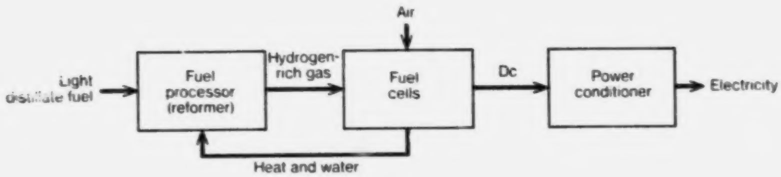

Air
Light distillate fuel
Fuel processor (reformer)
Hydrogen-rich gas
Fuel cells
Dc
Power conditioner
Electricity
Heat and water

Exhibit App B4-20b

DISPERSED FUEL CELLS

Region: East/West Central

	First Generation	Advanced
Unit Size--Net Electrical Output, MW	10	10
Available for Commercial Orders, Year	1984	1990
First Commercial Service, Year	1986	1992
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	3 x 10	3 x 10
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	555	540
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	555	540
Startup, Inventory, Land, Dec 1980 $	40	40
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	600	580
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	2.4	3.6
Incremental, mills/kWh:		
Variable	3.0	3.4
Consumable	-	-
Net Heat Rate, Btu/kWh		
Full Load	8300	7500
75% Load	8400	7300
50% Load	9000	-
25% Load	8400	-
Average Annual	8300	7300
Unit Availability[a]		
Planned Outage Rate, %	4.0	4.0
Unplanned Outage Rage, %	-[c]	-[c]
Equivalent Unplanned Outage Rate, %	5.6	5.6
Operating Availability, %	96.0	96.0
Equivalent Availability, %	90.6	90.6
Average Daily Unavailability, ADU, %	6.9	6.9
Capability Ratio	1.06	1.06
Duty Cycle	Intermediate	Intermediate
Minimum Load, %	25	25
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	1	1
Unit Life, Years	20	20
Technology Development Rating	3	2
Design & Cost Estimate Rating	4	2

---

[a] For mature plant

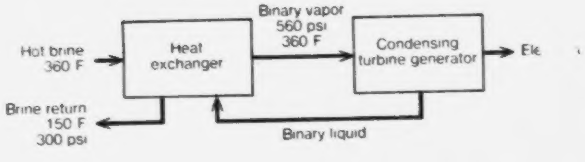
[b] See Section App B.4.8 for definition.

[c] Modularity and bypasses make full outages unlikely

Exhibit App B4-21a

GEOTHERMAL-BINARY

Brine solution from an underground reservoir is used to vaporize an isobutane/isopentane binary mixture. The binary vapor passes through a condensing turbine which generates electric power. The nominal temperature of the hot brine solution is 360°F. The cooled brine solution at a nominal temperature of 150°F returned to the reservoir.


Hot brine 360 F
Heat exchanger
Binary vapor 560 psi 360 F
Condensing turbine generator
Ele
Brine return 150 F 300 psi
Binary liquid

[redacted]

Exhibit App B4-21b

GEOTHERMAL BINARY[c,d]

Region: West (Southwest)

Unit Size--Net Electrical Output, MW	50
Available for Commercial Orders, Year	1986
First Commercial Service, Year	1990
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 50
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	725
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	735
Startup, Inventory, Land, Dec 1980 $	15
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	750
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	33.1
Incremental, mills/kWh:	
Variable	0.1
Consumable	1.8
Net Heat Rate, Btu/kWh	
Full Load	27,500
75% Load	-
50% Load	-
25% Load	-
Average Annual	28,300
Unit Availability[a]	
Planned Outage Rate, %	-
Unplanned Outage Rage, %	-
Equivalent Unplanned Outage Rate, %	-
Operating Availability, %	-
Equivalent Availability, %	-
Average Daily Unavailability, ADU, %	-
Capability Ratio	-
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing Design Time, Years	2
Idealized Construction Time, Years	2
Unit Life, Years	30
Technology Development Rating	3
Design & Cost Estimate Rating	3

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

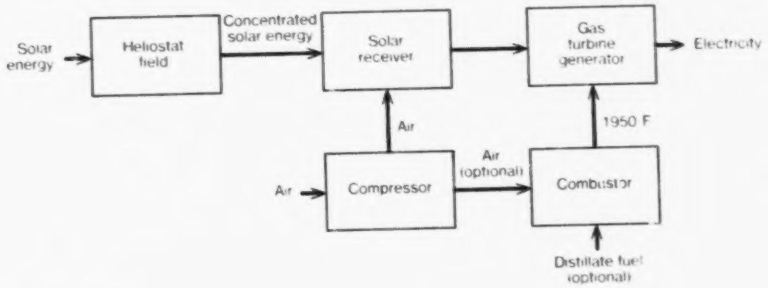
[c] Reference Report: Heber Geothermal Demonstration Power Plant, EPRI ER 1099, June 1979.

[d] Note that Costs Do Not include charges for the Geothermal Fluids.

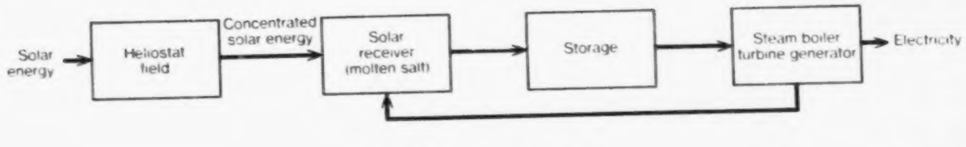
Exhibit App B4-22a

SOLAR CENTRAL RECEIVER

In the central receiver concept, solar energy is optically focused by a large array of two-axis tracking mirrors (heliostats) onto a central receiver or heat exchanger that is located on top of a central tower. In the hybrid concept, the receiver is a heat exchanger that performs the function of the combustor in a gas turbine/generator power cycle. A parallel combustor that fires low sulfur distillate oil operates when solar energy is not available. In the steam concept, a molten salt serves as a high temperature thermal storage system. The molten salt is cooled in a steam boiler which produces steam for a conventional steam turbine generator.


Solar energy
Heliostat field
Concentrated solar energy
Solar receiver
Gas turbine generator
Electricity
Air
1950 F
Air
Compressor
Air (optional)
Combustor
Distillate fuel (optional)

Hybrid Concept


Solar energy
Heliostat field
Concentrated solar energy
Solar receiver (molten salt)
Storage
Steam boiler turbine generator
Electricity

Molten Salt-Steam Concept

Exhibit App B4-22b

SOLAR CENTRAL RECEIVER[d]

Region: South Central (Southwest)

	Hybrid	Steam With 3-hr Storage
Unit Size--Net Electrical Output, MW	100	100
Available for Commercial Orders, Year	1992	1992
First Commercial Service, Year	1997	1997
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 100	1 x 100
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	2035[c]	2205[c]
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	2110	2290
Startup, Inventory, Land, Dec 1980 $	90	90
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	2200	2380
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	21	25
Incremental, mills/kWh:		
Variable	-	-
Consumable	-	0.5
Net Heat Rate, Btu/kWh (when firing gas turbine)		
Full Load	9800	n/a
75% Load	10,450	
50% Load	12,050	
25% Load	-	
Average Annual	10,100	
Unit Availability[a]		
Unplanned Outage Rage, %	-	-
Planned Outage Rate	-	-
Annual Availability	-	-
Duty Cycle	Intermediate	Intermediate
Minimum Load, %	-	-
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	3	3
Unit Life, Years	30	30
Technology Development Rating	2	2
Design & Cost Estimate Rating	2	1

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

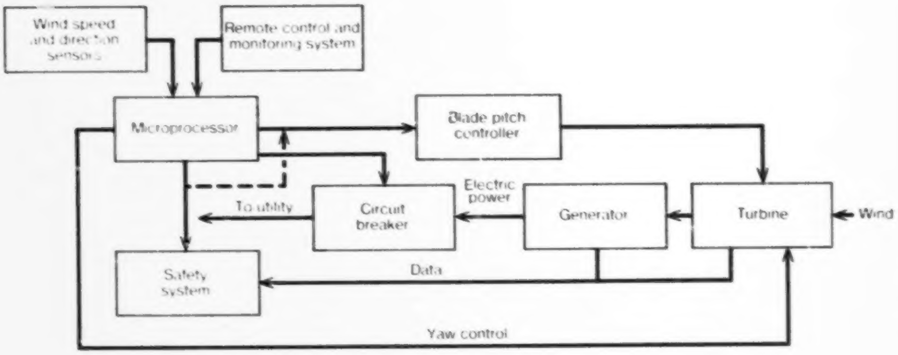
[c] Based on installed Heliostat cost of 130 $/M^2 (Dec. 1980 dollars)

[d] Reference Reports: Solar Thermal Conversion to Electric Power, EPRI ER-652, March 1978. Heliostat Cost Study, EPRI RP1091-1, In Publication.

Exhibit App B4-23a

WIND POWER

The kinetic energy in a moving airstream (wind) is used to drive a turbine, which in turn drives an electrical generator. In a representative current horizontal-axis design, a double-bladed rotor of 300 feet in diameter is mounted at its center to a 200-foot cylindrical tower. A representative rating is 2.5 megawatts, but machines rated up to 4 megawatts are under development in the United States and even larger designs are being studied internationally. Steel and wood-fiberglass composite rotors are in use. Typically, a machine will begin producing power at its "cut-in" wind speed, reach rated power at a somewhat higher wind speed, and continue producing rated power up through its "cut-out" wind speed at which the machine shuts down for self protection. For the representative wind machine discussed earlier, these critical design wind speeds are 14 mph, 27.5 mph, and 45 mph, respectively. The maximum survivable wind speed is 125 mph at hub height (top of tower) and the design life is 30 years. The synchronous generator for the representative machine is rated 2.5 megawatts, 3125 kVA, 4160 volts, 3-phase, 60 Hertz. Clustering machines at a site requires spacing equivalent to 10-20 rotor diameters between machines.


Wind speed and direction sensors
Remote control and monitoring system
Microprocessor
Blade pitch controller
Electric power
To utility
Circuit breaker
Generator
Turbine
Wind
Safety system
Data
Yaw control

[redacted]

Exhibit App B4-23b

WIND POWER

Region: East/West Central

Unit Size--Net Electrical Output, MW	2.5
Available for Commercial Orders, Year	1985
First Commercial Service, Year	1988
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	25 x 2.5
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	925
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	940
Startup, Inventory, Land, Dec 1980 $	30
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	970
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	9
Incremental, mills/kWh:	-
Performance at Sea Level	-
Wind Speed at 200 ft elevation, mph	% of Rated Output
14 or less	0
28-45	100
above 45	0 (shutdown)
Unit Availability[a]	
Planned Outage Rate, %	5.0
Unplanned Outage Rage, %	8.0
Equivalent Unplanned Outage Rate, %	8.0
Operating Availability, %	87.4
Equivalent Availability, %	87.4
Average Daily Unavailability, ADU, %	-
Capability Ratio	1.09
Duty Cycle	(c)
Minimum Load, %	10
Preconstruction, Licensing & Design Time, Years	2
Idealized Construction Time, Years	2
Unit Life, Years	30
Technology Development Rating	3
Design & Cost Estimate Rating	1

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Fuel displacement (typical capacity factor range: 30-40%)

Exhibit App B4-24a

MUNICIPAL REFUSE STEAM PLANT

Municipal solid waste (MSW) is a low quality fuel with low heat and high ash and moisture contents, typically, 4500 Btu/lb. It can be fired on a moving grate in a waterwall incinerator to produce steam for industrial use, cogeneration, or electricity generation. Ferrous metal can be recovered from the ash residues from the incinerator. The incineration plant consists of 8 operating and 2 spare units to allow planned maintenance without affecting steam generating capacity.

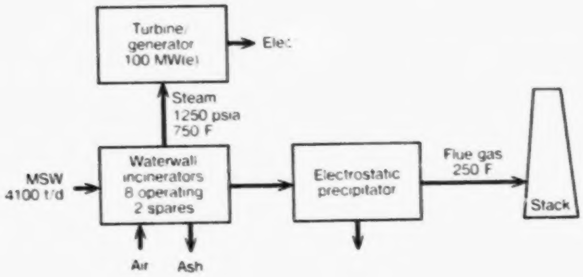

Turbine/
generator
100 MW(e)
Elec
Steam
1250 psia
750 F
MSW
4100 t/d
Waterwall
incinerators
8 operating
2 spares
Air
Ash
Electrostatic
precipitator
Flue gas
250 F
Stack

Exhibit App B4-24b

MUNICIPAL REFUSE STEAM PLANT

Region: East/West Central

Unit Size--Net Electrical Output, MW	100
Available for Commercial Orders, Year	Current
First Commercial Service, Year	Current
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 100
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	2500
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	2590
Startup, Inventory, Land, Dec 1980 $	200
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	2790
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	64.8
Incremental, mills/kWh:	
Variable	2.3
Consumable	3.6
Net Heat Rate, Btu/kWh	
Full Load	15970
Average Annual	16450
Unit Availability[a]	
Planned Outage Rate, %	6.6
Unplanned Outage Rage, %	1.5
Equivalent Unplanned Outage Rate, %	7.4
Operating Availability, %	92
Equivalent Availability, %	86.4
Average Daily Unavailability, ADU, %	6
Capability Ratio	1.08
Duty Cycle	Base
Minimum Load, %	25
Preconstruction, Licensing & Design Time, Years	4
Idealized Construction Time, Years	3
Unit Life, Years	20
Technology Development Rating	5
Design & Cost Estimate Rating	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Municipal Solid Waste as a Utility Fuel, EPRI RP 1225, In Publication.

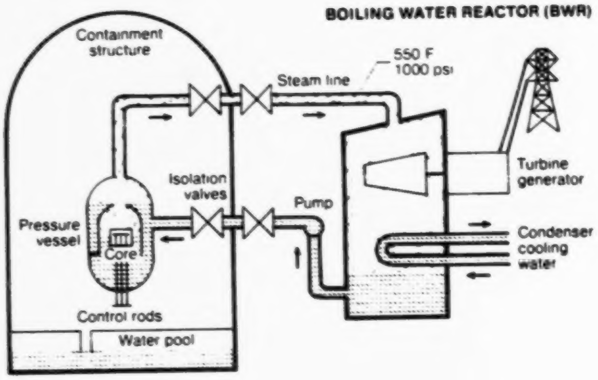
Exhibit App B4-25a

NUCLEAR LIGHT WATER REACTOR (LWR)

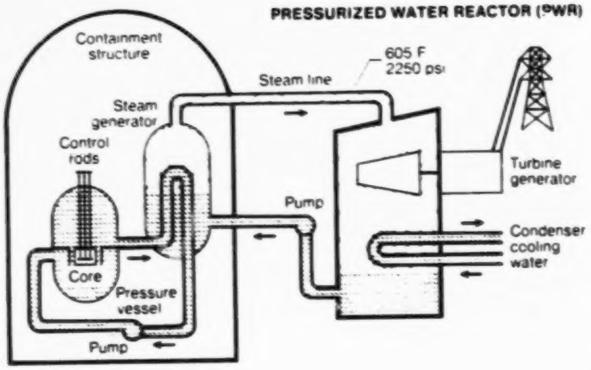
Cost and performance data are based on a typical design for a pressurized water reactor (PWR). The cost of boiling water reactors (BWR) are similar to PWR values, so for planning purposes the data would be representative of either type of design. Nearly all the reactors in commercial operation in the U.S. are of one of these two types of light water reactor systems (LWR). The costs do not reflect potential changes that may result from the Three Mile Island accident.

Schematic diagrams of the PWR and BWR systems are given to illustrate the principal components of equipment and operating pressures and temperatures.

BOILING WATER REACTOR (BWR)


Containment structure
550 F
1000 psi
Steam line
Isolation valves
Pressure vessel
Core
Pump
Turbine generator
Condenser cooling water
Control rods
Water pool

PRESSURIZED WATER REACTOR (PWR)


Containment structure
605 F
2250 psi
Steam line
Steam generator
Control rods
Turbine generator
Pump
Condenser cooling water
Core
Pressure vessel
Pump

[redacted]

Exhibit App B4-25b

NUCLEAR LIGHT WATER REACTOR (LWR)

Region: East/West Central

Unit Size--Net Electrical Output, MW	1000
Available for Commercial Orders, Year	Current
First Commercial Service, Year	Current
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	2 x 1000
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	1010
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1110
Startup, Land, Dec 1980 $	40
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1150
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	8.9
Incremental, mills/kWh:	
Variable	1.7
Net Heat Rate, Btu/kWh	
Full Load	
Average Annual	10,700
Unit Availability[a]	
Planned Outage Rate%	12.9
Unplanned Outage Rage, %	9.9
Equivalent Unplanned Outage Rate, %	21.7
Operating Availability, %	78.5
Equivalent Availability, %	68.2
Average Daily Unavailability, ADU, %	13
Capability Ratio	1.35
Duty Cycle	Base
Minimum Load, %	50
Preconstruction, Licensing & Design Time, Years	5
Idealized Construction Time, Years	6
Unit Life, Years	30
Technology Development Rating	5
Design & Cost Estimate Rating	2

---

[a] For mature plant - Does not include additional costs from Three Mile Island experience

[b] See Section App B.4.8 for definition.

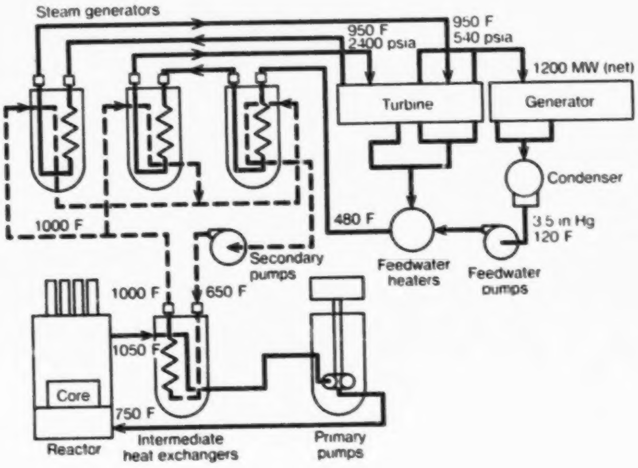
[redacted]

Exhibit App B4-26a

LIQUID METAL FAST BREEDER REACTOR (LMFBR)

The commercialization and cost of the liquid metal fast breeder reactor is difficult to determine in view of the present government policy and political environment. Cost estimates of LMFBR have been made independently by three manufacturers based upon a given scenario of light water reactor deployment in the future, and these data form the basis for the cost estimates contained in Exhibit App B4-26b.

A general type of design with typical operating parameters is shown in the block diagram below. Sodium is used as the reactor coolant and intermediate heat exchanges are used to transfer heat to the nonradioactive sodium that enters the steam generators. Other LMFBR designs use lower cycle temperatures to allow use of less advanced materials and components.


Steam generators
950 F
2400 psia
950 F
540 psia
1200 MW (net)
Turbine
Generator
Condenser
480 F
1000 F
3.5 in Hg
120 F
Secondary pumps
Feedwater heaters
Feedwater pumps
1000 F
650 F
1050 F
Core
750 F
Reactor
Intermediate heat exchangers
Primary pumps

[redacted]

Exhibit App B4-26b

LIQUID METAL FAST BREEDER REACTOR

Region: East/West Central

Unit Size--Net Electrical Output, MW	1000
Available for Commercial Orders, Year	1992
First Commercial Service, Year	2002
Unit Capital Costs[a], \$/kW (net) based on Plant Size of (number of units x unit size)	2 x 1000
Total Plant Cost, Dec 1980 \$ (based on overnight construction)[b]	1275
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	1400
Startup, Land, Dec 1980 \$	50
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	1450
Operation and Maintenance Costs[a], 1981 Costs in Dec 1980 \$	
Fixed, \$/kW-yr	11.1
Incremental, mills/kWh:	
Variable	2.1
Net Heat Rate, Btu/kWh	
Full Load	
Average Annual	10,000
Unit Availability[a]	
Planned Outage Rate, %	12.9
Unplanned Outage Rage, %	21.7
Equivalent Unplanned Outage Rate, %	21.7
Operating Availability, %	68.2
Equivalent Availability, %	68.2
Average Daily Unavailability, ADU, %	-
Capability Ratio	1.46
Duty Cycle	Base
Minimum Load, %	-
Preconstruction, Licensing & Design Time, Years	5
Idealized Construction Time, Years	6
Unit Life, Years	30
Technology Development Rating	3
Design & Cost Estimate Rating	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

App B.5 ENERGY STORAGE DATA

The development of the energy storage data parallels the generation data discussed in Section App B.4 of Appendix B. Since the size of the storage has a strong influence on the performance of the storage technology the cost of the storage portion of the plant is broken out separately from the Power Charging/Generation Section.

[redacted]

Exhibit App B5-1a

BATTERY STORAGE SYSTEM

Off-peak electric power is used to charge an improved lead acid battery or an advanced battery based on either the sodium-sulfur or the zinc-chlorine system. The battery system is composed of modular units. Battery capital costs are based on a production rate of ten, 20 MW units per year for lead acid and twenty-five, 20 MW units per year for the advanced battery. The advanced power converter costs are based on a production of 1500 MW per year.

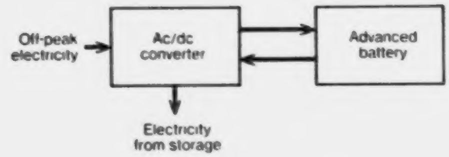

Off-peak electricity
Ac/dc converter
Advanced battery
Electricity from storage

Exhibit App B5-1b

BATTERY STORAGE SYSTEM (3-HOUR LEAD ACID AND 5-HOUR ADVANCED)

Region: All Regions

	Lead Acid	Advanced
Unit Size--Net Electrical Output, MW	20	20
Storage Size, Hours	3	5
Available for Commercial Orders, Year	Current	1988
First Commercial Service, Year	1984	1993
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 20	1 x 20
Power Charging/Generation	70	70
Storage	560	590
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	630	660
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	640	670
Startup, Land, Dec 1980 $	10	10
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	650	680
Operation and Maintenance Costs, 1981 Costs in Dec 1980 $		
Fixed, $/kW-yr	1.1	1.1
Incremental, mills/kWh:		
Variable	3.3	3.3
Battery Replacement	30	15
Efficiency (kWh Output/kWh Input)		
Full Load	0.72	0.68-0.72
75% Load	0.76	0.72-0.76
50% Load	0.80	0.76-0.8
Average Annual	0.72	0.70
Unit Availability[a]		
Planned Outage Rate, %		8.3
Unplanned Outage Rage, %		0.3
Equivalent Unplanned Outage Rate, %		13.3
Operating Availability, %		91.4
Equivalent Availability, %		79.5
Average Daily Unavailability, ADU, %		15
Capability Ratio		1.15
Duty Cycle	Peaking	Peaking
Minimum Load, %	10	10
Preconstruction, Licensing & Design Time, Years	2	2
Idealized Construction Time, Years	2	2
Unit Life, Years	25	25
Technology Development Rating	4	3
Design & Cost Estimate Rating	3	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[redacted]

Exhibit App B5-2a

UNDERGROUND PUMPED HYDRO SYSTEM

Underground pumped hydro is similar to conventional hydro except the powerhouse and the lower reservoirs are located underground. The configuration is based on six 333-MW units arranged in three-unit pairs of 666 MW each. Each unit pair represents a two step arrangement with an intermediate and a lower powerhouse. Limitations on the total head (elevation) for commercially available reversible pump turbines prevent a single 5000 ft drop with a single underground reservoir. The reservoirs are sized for 10 hours of storage.

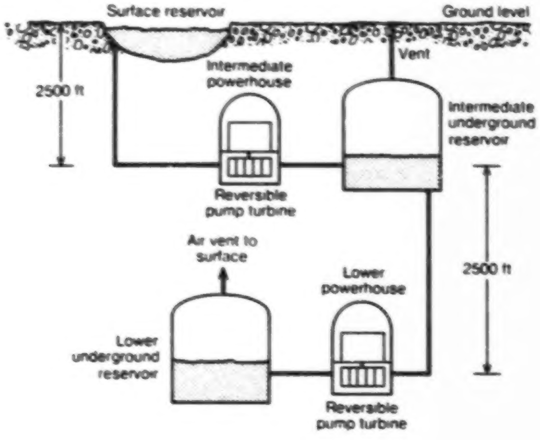

Surface reservoir
Ground level
Vent
Intermediate powerhouse
2500 ft
Intermediate underground reservoir
Reversible pump turbine
Air vent to surface
Lower powerhouse
2500 ft
Lower underground reservoir
Reversible pump turbine

Exhibit App B5-2b

UNDERGROUND PUMPED HYDRO STORAGE SYSTEM (2 STEP)[c]

Region: All Regions

Unit Size--Net Electrical Output, MW	667
Storage Size, Hours	10
Available for Commercial Orders, Year	1982
First Commercial Service, Year	1991
Unit Capital Costs[a], $/kW (Net) based on Plant Size of (number of units x unit size)	3 x 667
Power Charging/Generation	265
Storage	400
Total Plant Cost, Dec 1980 (based on overnight construction)[b]	665
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	725
Startup, Inventory, Land, Dec 1980 $	15
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	740
Operation and Maintenance Costs, 1981 Costs in Dec 1980 $	
Fixed, $/kW-yr	1.7
Incremental, mills/kWh:	
Variable	0.2
Consumable	-
Efficiency (kWh Output/kWh Input)	
Full Load	0.72
75% Load	0.70
Average Annual	0.71
Plant (2000 MW) Availability[a]	
Planned Outage Rate, %	2
Unplanned Outage Rage, %	0.6
Equivalent Unplanned Outage Rate, %	2.1
Operating Availability, %	94.4
Equivalent Availability, %	96.0
Average Daily Unavailability, ADU, %	1.5
Capability Ratio	1.04
Duty Cycle	Peaking
Minimum Load, %	50
Preconstruction, Licensing & Design Time, Years	3
Idealized Construction Time, Years	6
Unit Life, Years	50
Technology Development Rating	3
Design & Cost Estimate Rating	3

---

[a] For mature plant

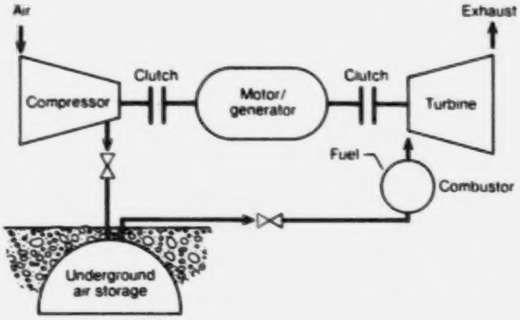
[b] See Section App B.4.8 for definition.

[c] Underground Pumped Hydro and CAEs in Hard Rock, EPRI EM 1589, April 1981.

Exhibit App B5-3a

COMPRESSED AIR ENERGY STORAGE (CAES)

Compressed air storage is based on using an electric motor driver compressor that pressurizes an underground cavern (in a salt or rock structure) with air during off-peak periods. When the stored energy is needed, the air is expanded through a combustion turbine/generator which is fired with a low sulfur distillate fuel. The reservoir is either a solution mined salt cavern, a conventionally mined rock cavern, or a suitable aquifier. With the rock cavern a surface water reservoir is connected to the underground reservoir by a vertical water shaft to maintain approximately constant pressure in the underground reservoir. The aquifier reservoir requires a well field composed of 40 wells (30 operating and 10 spare).


Air
Exhaust
Clutch
Clutch
Compressor
Motor/
generator
Turbine
Fuel
Combustor
Underground
air storage

Compressed air storage system

Exhibit App B5-3b

COMPRESSED AIR ENERGY STORAGE (CAES)[c]

Region: East/West Central

	Storage Medium		
	Rock	Salt	Aquifer
Unit Size--Net Electrical Output, MW	220	220	220
Storage Size, Hours	10	10	10
Available for Commercial Orders, Year	1982	1982	1983
First Commercial Service, Year	1988	1987	91
Unit Capital Costs[a], $/kW (net) based on Plant Size of (number of units x unit size)	1 x 220	1 x 220	1 x 220
Power Charging/Generation	424	424	424
Storage (10 hrs)	101	66	61
Total Plant Cost, Dec 1980 $ (based on overnight construction)[b]	525	490	485
Total Plant Investment, Jan 1981 In-Service (includes AFDC)	555	510	530
Startup, Inventory, Land, Dec 1980 $	25	25	25
Total Capital Requirement, Jan 1981 In-Service (includes AFDC)	580	535	555
Operation and Maintenance Costs, 1981 Costs in Dec 1980 $			
Fixed, $/kW-yr	3.8	3.8	3.8
Incremental, mills/kWh:			
Variable	0.5	0.4	5.4
Consumables (Makeup Cooling Water)	-	0.2	
Energy Requirement per kWh Output	kWh + Btu (Fuel)	Same as Rock	Same as Rock
Full Load	0.74 + 4020		
75% Load	0.78 + 4070		
50% Load	0.88 + 4220		
Average Annual	0.76 + 4115		
Plant Availability[a]			
Planned Outage Rate, %	2	2	2
Unplanned Outage Rage, %	5.6	5.6	5.6
Equivalent Unplanned Outage Rate, %	5.6	5.6	5.6
Operating Availability, %	98	92.5	92.5
Equivalent Availability, %	92.5	92.5	92.5
Average Daily Unavailability, ADU, %	5.6	0	0
Capability Ratio	1.07	1.07	1.07
Duty Cycle	Peaking	Peaking	
Minimum Load, %	10	10	10
Preconstruction, Licensing Design Time, Years	2	2	2
Idealized Construction Time, Years	4	3	6
Unit Life, Years	30	30	30
Technology Development Rating	4	4	3
Design & Cost Estimate Rating	3	3	2

---

[a] For mature plant

[b] See Section App B.4.8 for definition.

[c] Reference Report: UPH and Compressed Air Energy Storage in Hard Rock, EPRI EM-1589, April 1981.

[redacted]

App B.6 LOAD MANAGEMENT AND CONSERVATION (Not Complete)

App B.7 ELECTRICAL TRANSMISSION

App B.7.1 General

Typical data for alternating current transmission lines and substation equipment are given in this section. No typical data can be given at this time for direct current lines and substation equipment, as each installation to date has been designed on an individual basis.

The ac transmission lines and transformers are assumed to have the same physical characteristics as the typical lines and transformers described in Section 4 of EPRI publication EM-285, Synthetic Electric Utility Systems for Evaluating Advanced Technologies. Even so, the cost of installing electrical transmission equipment is very site specific and the information contained in this section should be used only when no better data exists. All costs are given in December 1980 dollars and are assumed to escalate at the rate of inflation found in Appendix A.

App B.7.2 Transmission Lines

Single circuit ac transmission line data are listed in Exhibit App B7-1. Transmission circuit ratings are determined by some combination of conductor thermal capacity, terminal reactive supply, shunt and series compensation, voltage drop limitations, and system stability constraints and are generally expressed as a per unit of the surge impedance loading (SIL).* A curve of maximum transmission circuit loading for uncompensated circuits is shown in Exhibit App B7-2, in terms of SIL.

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* $\text{SIL} = \dfrac{kV}{\frac{L}{C}}$

kV = line-to-line voltage
L = line inductance
C = line capacitance

Exhibit App B7-1

SINGLE CIRCUIT AC TRANSMISSION LINE DATA

Voltage kV	Dec 1980 Installed Cost* 1000s Dollars/Mile	Surge Impedance Loading (SIL) MVA	Typical Line Loading MVA		Typical Right-of-Way Width (ft)
			100 Mile Line (2 x SIL)	300 Mile Line (1 x SIL)	
115	100-300	35	70	35	100
138	100-300	50	100	50	100
230	100-300	137	274	137	125
345	175-440	415	830	415	150
500	320-460	842	1,684	842	200
765	400-600	2,868	4,536	2,268	250
1100	500-750**	5,181	10,362	5,181	300

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*Land and right-of-way costs are not included.
Lower value for multiple pole-single circuit.
Upper and single values for steel tower-single circuit.

**Line costs extrapolated from lower voltages.

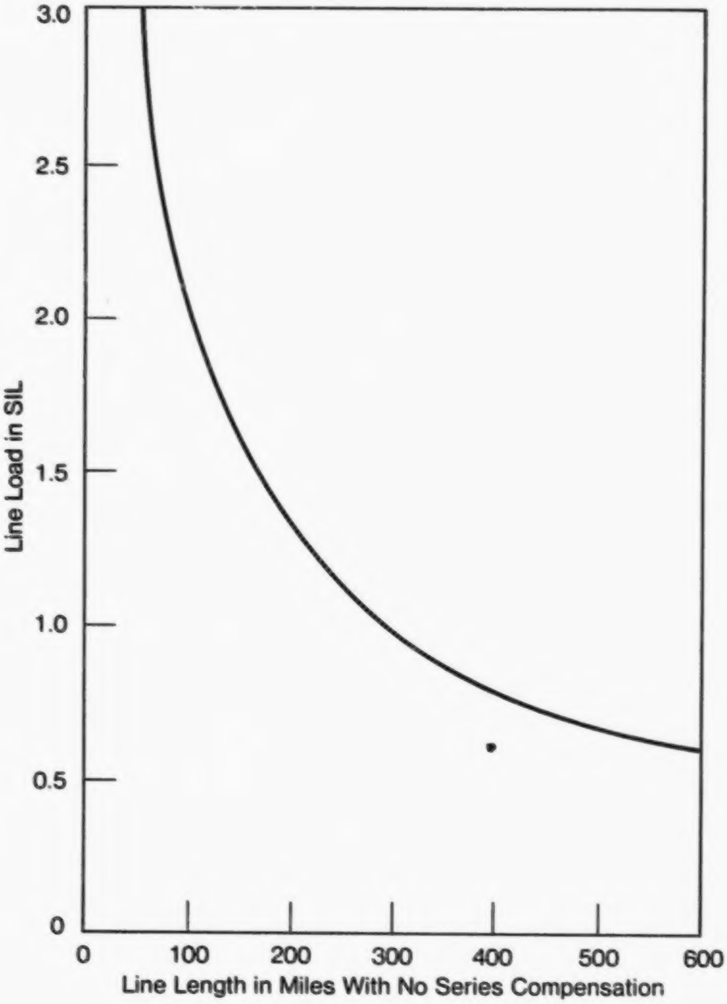

Exhibit App B7-2 Transmission Line Capability in Terms of Surge Impedance Loading

[redacted]

The installed cost transmission lines can vary significantly because of tower and conductor design considerations and right-of-way costs. For EPRI use, base estimated installed costs, for single circuit transmission lines are given in Exhibit App B7-1 and do not include land and right-of-way (ROW) costs. Land and ROW costs also vary widely depending on the type of land use agreement, urban, rural, etc. Ranges of 20 to 1 are typically found in farmland costs. For EPRI purposes, land use costs are estimated to range between 3% to 7% of the line cost with 5% being a reasonable midpoint value. Many of the lower voltage lines are installed on double circuit steel towers. The ratio of cost for a double circuit steel tower and a single circuit steel tower (ROW cost no included) is as follows:

kV	Cost Ratio
111-138	1.37
230	1.43
345	1.58

App B.7.3 Circuit Breakers

The estimated installed costs for circuit breakers, listed in Exhibit App B7-3, are based on December 1980 selling prices for the circuit breakers, plus an adder for installation, associated equipment, wiring, and controls, etc. These are average values for estimating costs of installing circuit breakers in new substations, or of adding circuit breakers to existing substations.

Exhibit App B7-3

CIRCUIT BREAKERS INSTALLED COSTS
(Dec 1980 $)

Voltage kV	Total Installed Cost (dollars x 1,000)
115-161	255
230	330
345	695
500	1385
765	1750

App B.7.4 Transformers

The estimated installed cost for a transformer is based on the sum of the selling price for the transformer, the estimated cost for the installation, and the accessory equipment all stated in December 1980 dollars. These values may be used when adding a transformer to an existing location or installing a transformer at a new location. The installed cost for bulk power step-up (generating station) transformers and step-down (substation) transformers, and distribution substation transformers are listed in Exhibits App B7-4 and App B7-5 respectively.

The transmission step-down transformers were assumed to be auto transformers with a delta tertiary. It was assumed that the generation step-up transformers are FOA and delta-wye connected. The distribution substation transformers were assumed to be delta-wye connected. Estimated costs for a plus or minus 10% load tap changer for the distribution substation transformers are listed in Exhibit App B7-5. The cost of the load tap changer must be added to the base cost when it applies.

[redacted]

Exhibit App B7-4

BULK POWER TRANSFORMER COSTS[a]
(December 1980 dollars)

Voltage kV	Unit 3 Phase Rating MVA	Total Installed Cost (dollars x 1,000)
765	550 to 1,100	5600 to 7300
500	275 to 1,100	2730 to 4970
345	165 to 1,100	1840 to 3420
230/161	55 to 550	1050 to 2160
138/115	55 to 550	870 to 1950

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[a] Approximate cost of intermediate size may be obtained by linear interpolation.

Exhibit App B7-5

DISTRIBUTION SUBSTATION TRANSFORMER COSTS[a]
(December 1980 dollars)

Voltage kV	Unit Rating OA/FOA/FOA MVA	Total Installed Cost[b] (dollars x 1,000)	Load Tap Changer Cost (dollars x 1,000)
230	60/80/100	870	165
	12/16/20	520	90
161	60/80/100	815	165
	12/16/20	475	80
138	60/80/100	770	155
	12/16/20	365	65
115	60/80/100	750	155
	12/16/20	405	60

---

[a] Approximate cost of intermediate sizes may be obtained by linear interpolation.

[b] The cost of the LTC is not included in the total installed cost.

APPENDIX C

UNCERTAINTY DATA

Exhibit App C-1

UNCERTAINTY DATA
FIRST COMMERCIAL SERVICE YEAR

	Probability of Occurrence		
	0.25	0.50	0.25
1. Coal Steam, Wet Limestone FGD			
a. supercritical (500 MW)		Current	
b. subcritical (500 MW)		Current	
2. Coal Steam with Regenerative FGD			
a. current		Current	
b. advanced		Not included	
3. Advanced Pulverized Coal-Steam		Not included	
4. Atmospheric Fluidized Bed			
a. bituminous	1990	1995	2003
b. subbituminous	1990	1995	2003
5. Pressurized Fluidized Bed (bituminous)	1991	2000	2008
6. Gasification Combined Cycle			
a. Texaco			
- current	1988	1992	1998
- advanced		Not included	
b. BGC/Lurgi Slagger		Not included	
c. Advanced Fuel Cell		Not included	
7. Gasifier-Fired Boiler		(earliest 1990)	
8. Magnetohydrodynamic (subbituminous)		Not included	
9. Solid Solvent Refined Coal		Not included	
10. Liquid Fuel Steam			
a. distillate		Current	
b. residual		Current	
11. Liquid Fuel Combined Cycle			
a. currrent			
- distillate		Current	
- residual		Current	
b. advanced			
- distillate		Not included	
- residual		Not included	

Exhibit App C-1

UNCERTAINTY DATA
FIRST COMMERCIAL SERVICE YEAR

	Probability of Occurrence		
	0.25	0.50	0.25
12. Liquid Fuel Combustion Turbine			
a. current			
- distillate		Current	
- residual		Current	
b. advanced			
- distillate		Not included	
- residual		Not included	
13. Dispersed Fuel Cell			
a. first	1984	1986	1987
b. advanced	1986	1988	1992
14. Geothermal Binary		Not included	
15. Solar Thermal			
a. hybrid		Not included	
b. steam with storage		Not included	
16. Wind		Not included	
17. MSW		Not included	
18. Nuclear			
a. LWR		Current	
b. breeder		Not included	
19. Batteries			
a. lead acid		Current	
b. advanced (sodium sulfur)	1990	1993	1995
20. Underground Pumped Hydro		Current	
21. Compressed Air			
a. rock	1985	1986	1987
b. salt	1985	1986	1987

[redacted]

Exhibit App C-2

UNCERTAINTY DATA
TOTAL CAPITAL REQUIREMENTS
(January 1981 $/kW)

	Probability of Occurrence		
	0.25	0.50	0.25
1. Coal Steam, Wet Limestone FGD			
a. supercritical (500 MW)	900	995	1120
b. subcritical (500 MW)	900	995	1120
2. Coal Steam with Regenerative FGD			
a. current		Not included	
b. advanced		Not included	
3. Advanced Pulverized Coal-Steam		Not included	
4. Atmospheric Fluidized Bed			
a. bituminous	680	890	1135
b. subbituminous		Not included	
5. Pressurized Fluidized Bed (bituminous)	770	955	1665
6. Gasification Combined Cycle			
a. Texaco			
- current	895	1090	1260
- advanced		Not included	
b. BGC/Lurgi Slagger		Not included	
c. Advanced Fuel Cell		Not included	
7. Gasifier-Fired Boiler	1000	1200	1390
8. Magnetohydrodynamic (subbituminous)		Not included	
9. Solid Solvent Refined Coal		Not included	
10. Liquid Fuel Steam			
a. distillate		Not included	
b. residual		Not included	
11. Liquid Fuel Combined Cycle			
a. currrent			
- distillate	395	470	550
- residual	455	540	640
b. advanced			
- distillate	400	510	595
- residual	455	585	685

[redacted]

Exhibit App C-2

UNCERTAINTY DATA
TOTAL CAPITAL REQUIREMENT
(January 1981 $/kW)

	Probability of Occurrence		
	0.25	0.50	0.25
12. Liquid Fuel Combustion Turbine			
a. current			
- distillate		Not included	
- residual		Not included	
b. advanced			
- distillate		Not included	
- residual		Not included	
13. Dispersed Fuel Cell			
a. first	535	665	1000
b. advanced	535	665	1000
14. Geothermal Binary		Not included	
15. Solar Thermal Control Receiver			
a. hybrid		Not included	
b. steam with storage		Not included	
16. Wind		Not included	
17. MSW		Not included	
18. Nuclear			
a. LWR	1100	1150	1400
b. breeder	1400	1450	1800
19. Batteries			
a. lead acid		Not included	
b. advanced (sodium sulfur)	385	540	820
20. Underground Pumped Hydro	475	735	1030
21. Compressed Air			
a. rock	470	550	700
b. salt	430	500	650

Exhibit App C-3

UNCERTAINTY DATA
EQUIVALENT UNPLANNED OUTAGE RATES

	Probability of Occurrence		
	0.25	0.50	0.25
1. Coal Steam, Wet Limestone FGD			
a. supercritical (500 MW)	15.0	18.2	21.9
b. subcritical (500 MW)	15.0	18.2	21.9
2. Coal Steam with Regenerative FGD			
a. current	13.2	16.4	20.4
b. advanced	13.2	16.4	20.4
3. Advanced Pulverized Coal-Steam		Not included	
4. Atmospheric Fluidized Bed			
a. bituminous	13.6	16.5	19.6
b. subbituminous	13.6	16.5	19.6
5. Pressurized Fluidized Bed (bituminous)	11.9	15.0	18.0
6. Gasification Combined Cycle			
a. Texaco			
- current	7.0	9.1	11.3
- advanced	8.8	11.6	14.3
b. BGC/Lurgi Slagger	8.4	10.7	13.1
c. Advanced Fuel Cell	8.4	10.7	13.1
7. Gasifier-Fired Boiler	17.8	21.4	25.3
8. Magnetohydrodynamic (subbituminous)	23.6	28.5	33.3
9. Solid Solvent Refined Coal	9.1	11.3	14.1
10. Liquid Fuel Steam			
a. distillate	9.1	11.3	14.1
b. residual	9.1	11.3	14.1
11. Liquid Fuel Combined Cycle			
a. currrent			
- distillate	4.6	7.4	10.9
- residual	5.6	9.0	13.3
b. advanced			
- distillate	3.7	5.9	8.6
- residual	4.7	7.5	11.0

Exhibit App C-3

UNCERTAINTY DATA
EQUIVALENT UNPLANNED OUTAGE RATES

	Probability of Occurrence		
	0.25	0.50	0.25
12. Liquid Fuel Combustion Turbine			
a. current			
- distillate	4.8	8.0	12.0
- residual	6.0	10.0	15.0
b. advanced			
- distillate	3.6	6.0	9.0
- residual	4.8	8.0	12.0
13. Dispersed Fuel Cell			
a. first	3.6	5.6	7.9
b. advanced	3.6	5.6	7.9
14. Geothermal Binary		Not included	
15. Solar Thermal			
a. hybrid		Not included	
b. steam with storage		Not included	
16. Wind	4.8	8.0	12.0
17. MSW	5.0	7.4	11.3
18. Nuclear			
a. LWR		Not included	
b. breeder		Not included	
19. Batteries			
a. lead acid		Not included	
b. advanced (sodium sulfur)	8.8	13.3	18.6
20. Underground Pumped Hydro		Not included	
21. Compressed Air			
a. rock	3.4	5.6	8.3
b. salt	3.4	5.6	8.3

BACKGROUND
FOR
EPRI
R&D
EVALUATION

205

Chapter B-1

PRESENT WORTH ARITHMETIC

B-1.1 INTRODUCTION

Almost any economic comparison of alternatives involves the use of relatively simple present worth arithmetic. Present worth arithmetic is a generic term for the mathmetical operation that involves the use of the expression

$$(1+b)^n \qquad \text{B-1.1-1}$$

where $\underline{b}$ is the rate of change in a time period and $\underline{n}$ is the number of periods. Present worth arithmetic is used in the TAG for two purposes:

- To determine the present value of an array of monetary amounts which occur at different times in order to establish an equivalent single monetary amount that can be compared to other time equivalent amounts at the same point in time
- To quantify the effects of escalation and inflation

Section B-1.2 will deal with the concept of present value. Escalation and inflation will be covered in Section B-1.3.

B-1.2 PRESENT VALUE

The term "present value" is the equivalent of a monetary amount at a point in time other than that at which it is paid or received. The term does not necessarily denote the present time (today).

In any analysis involving economic value there are always two variables, money and time. Because of the time value of money, monetary amounts cannot be added or compared directly unless they occur at the same point in time. Money has time value since it can be invested for intervals of time with a promised gain in value.

[redacted]

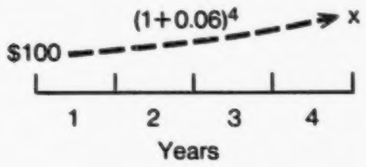
The basic expression used to calculate the time equivalent of money at a different point in time is

$$(1+i)^n \qquad \text{B-1.2-1}$$

Where i is the discount rate, or the time value of money per time period, and n is the number of periods. Depending on the context, i may be designated "interest rate" when a loan is involved or "cost of money" when an industrial investment is involved. In the context of the TAG, i, the time value of money is the cost of money. To determine the present value of money n periods into the future, multiply by the expression $(1+i)^n$. The expression B-1.2-1 is called the compound amount factor for a single payment.

Example B-1-1: At a 6% discount rate, \$100 today would be equivalent to what dollar amount four years from now?

In solving problems that include both money and time, it is often helpful to include a time diagram that shows the relationships of the variables. Thus:



And using B-1.2-1,

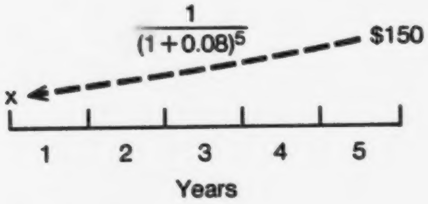
$$\begin{aligned} x &= \$100\,(1+i)^n \\ &= \underline{\underline{\$126.25}} \end{aligned}$$

To determine the present value of money n periods in the past, multiply by the expression

$$\frac{1}{(1+i)^n} \qquad \text{B-1.2-2}$$

In most texts, the expression B-1.2-2 is called the present worth factor for a single payment.

Example B-1-2: At an annual discount rate of 8%, \$150.00 five years from now would have what value today?



And using B-1.2-2

$$x = \$150\left(\frac{1}{(1+0.08)^5}\right)$$
$$= \underline{\underline{\$102.40}}$$

In the context of the TAG, the computation of the value of money at an earlier date (discounting) is the more common arithmetic operation. The expression for discounting is identified by the symbol $\underline{v^n}$.

$$v^n = \frac{1}{(1+i)^n} \qquad \text{B-1.2-3}$$

To keep the number of symbols to a minimum so as to minimize confusion by the user of the TAG, the compilation of the value of money at a later date (compounding) will be accomplished by multiplying by the reciprocal of $\underline{v^n}$. Thus,

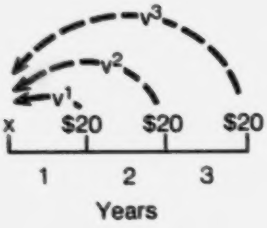
$$\frac{1}{v^n} = (1+i)^n \qquad \text{B-1.2-4}$$

While the expression $\underline{v^n}$ could be used to solve any present value problem that would arise in the use of this economic evaluation technique, it will be convenient to define a second term in order to speed the arithmetic process.

An annuity is a series of equal annual amounts occurring over a period of time. Thus, \$20 at the end of the first year, \$20 at the end of the second year, and \$20 at the end of the third year could be described as a three-year annuity beginning at the end of year one. The determination of the present value of an annuity is illustrated in the following examples.

Example 1-3: Determine the present value of the annuity described in the paragraph above at an annual discount rate of 8%. The present value could be obtained with the use of the v^n factor already developed:

Thus,



$$\begin{aligned} x &= \$20\,v^1 + \$20\,v^2 + \$20\,v^3 \\ &= \$20\,(0.926 + 0.857 + 0.794) \\ &= \$20\,(2.577) \\ &= \underline{\underline{\$51.54}} \end{aligned}$$

It will be convenient to define a factor a_3 equal to the sum of the present value factors $v^1 + v^2 + v^3$. Or, in general,

$$a_n = v^1 + v^2 + v^3 + \cdots + v^n \qquad \text{B-1.2-5}$$

It can be shown that

$$a_n = \frac{1-v^n}{i} \qquad \text{B-1.2-6}$$

This equation is often expressed in financial handbooks as

$$a_n = \frac{(1+i)^n - 1}{i\,(1+i)^n} \qquad \text{B-1.2-7}$$

or as

$$a_n = \left(\frac{1-v^n}{1-v}\right)v \qquad \text{B-1.2-8}$$

The factor a_n is the present worth factor for a uniform series. It is also referred to as the cumulative present worth factor. The reciprocal is called the capital recovery factor for a uniform series.

Example B-1-4: Repeat Example B-1-3, but use the a_n factor to find the present value.

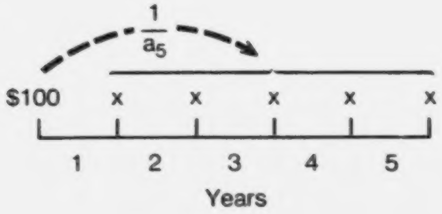
$$\begin{aligned} x &= \$20a_3 \\ &= 20\,(2.577) \\ &= \underline{\underline{\$51.54}} \end{aligned}$$

Note that the present value of a uniform series using the a_n factor of B-1.2-5 is always at a point in time that is one year prior to the first transaction.

In addition to using the a_n factor to compute the present value of an annuity, the reciprocal can be used to obtain the uniform annual amount equivalent to a single sum of money.

Example B-1-5: $100 is equivalent to what annual 5-year payment beginning at the end of the first year? Use an interest rate of 8%.

Again, using the time diagram approach,



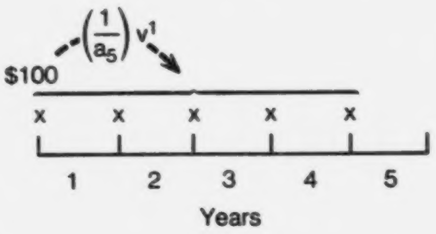
$$x = \frac{\$100}{a_5}$$

$$= \frac{100}{3.993}$$

$$= \underline{\underline{\$25.04}}$$

This process is a segment of the procedure known as levelization.

Example B-1-6: Repeat Example B-1-5, except that the first payment of the 5-year uniform series is made at the beginning of the first year and succeeding payments are made at the beginning of each of the next four years. Since the $\overline{a_n}$ factor results in a uniform series which begins at the end of the first year, it is necessary to move the entire array backwards one year by multiplying by $\underline{v^1}$.



$$x = \frac{\$100}{a_5}\ (v^1)$$

$$= \frac{100}{3.993}\ (0.926)$$

$$= \underline{\underline{\$23.19}}$$

B-1.3 ESCALATION AND INFLATION

As late as the 1960's when the annual inflation rate was 1 to 2 percent and natural resources appeared to be plentiful, cost increases due to escalation were modest and generally were not included in economic studies. Beginning in the 1970s, the inflation rate became significant, and it has now become prudent to quantify the effects of cost increases in economic analyses.

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In dealing with certain expenditures that will occur at a future time, it is necessary to consider the effect of both the real escalation rate and the inflation rate.

The real escalation rate is defined as the annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand and improvements in design or manufacturing (negative rate), whereas inflation is defined as the rise in price levels caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal quality. The real escalation rate is independent and exclusive of inflation.

The apparent escalation rate is the total annual rate of increase in cost. The apparent escalation rate includes the effect of both the real escalation rate and inflation. The relationship between real escalation, apparent escalation and inflation is as follows:

$$(1+e_a)^n = [(1+e_r)(1+e_i)]^n \qquad \text{B-1.3-1}$$

$$e_a = [(1+e_r)(1+e_i)]-1 \qquad \text{B-1.3-2}$$

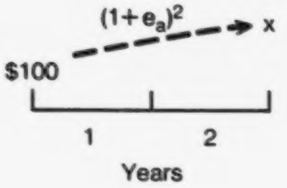
Where e_a = apparent annual escalation rate,
e_r = real annual escalation rate,
e_i = annual inflation rate,
n = number of years.

Note that the equation to determine the apparent escalation is of the form $(1+b)^n$ and is similar to the equation used for the present value computation. Both processes are illustrated below.

Example B-1-7: If the price of a certain expenditure is $100 now, the annual real escalation rate is 0.8% and the annual inflation rate 6%, would there be an advantage in making the expenditure now instead of two years hence when it would be required? Assume that the discount rate is 10%.

To solve this problem, it will be necessary first to escalate the expenditure for two years and second to present value the escalated payment to today in order to compare with the original $100. Using a time diagram and Equation 1.3-1 the escalation will be determined.

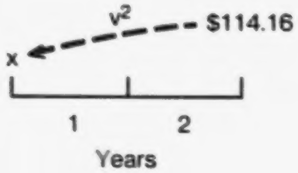
[redacted]



$$
\begin{aligned}
(1+e_a)^2 &= [(1+0.008)\,(1+0.06)]^2 \\
&= \underline{\underline{1.1416}}
\end{aligned}
$$

Thus, $100 today will escalate to $114.16 in two years.

To compare the $114.16 two years hence with $100 today, it is necessary to present value the $114.16 payment to the same point in time as the $100 payment.



$$
\begin{aligned}
x &= \$114.16\,v^2 \\
&= \$114.16 \left(\frac{1}{(1+0.10)^2}\right) \\
&= \underline{\underline{\$94.35}}
\end{aligned}
$$

Since the present value of $114.16, payable two years hence, is $94.35 today, it would be better to delay the purchase of the $100 expense item to the time when it would be required even in the face of inflation and therefore take advantage of the "time value of money."

Note the difference between expressing an expenditure in terms of dollars valued at another time and expressing the present value of an expenditure in a different reference year. To express a payment subject to escalation in terms of dollars valued at another time, the apparent escalation rate is used. In Example B-1-7, the initial $100 escalates to $114.16 in two years. To determine the present worth of a payment in a reference year, the discount rate is used. Note that in both processes, the expression with the general form $(1+b)^n$ is used.

An analysis that includes the effect of escalation is said to be made in current dollars. If inflation is not included, the analysis is said to be made in constant dollars. A further discussion of escalation and inflation including the effect of inflation on the discount rate is covered in Section B-2.6.

B-1.4 LEVELIZATION AND ESCALATION

This section will discuss the levelized value of a non-uniform payment schedule subject to a constant apparent escalation rate. An equivalent annual (levelized) payment forms the basis of one method of comparing alternatives and will be discussed in more detail in later chapters. The effect of escalation was introduced in Section B-1-3 and one segment of the concept of levelization in Example B-1-5.

If a series of payments is uniform over time except for a constant apparent escalation, the levelized value of the series can be computed by multiplying the initial monetary amount by the levelization factor, $\underline{L_n}$.

$$L_n = \frac{k(1-k^n)}{a_n(1-k)} \qquad \text{B-1.4-1}$$

where

$$k = \frac{1+e_a}{1+i} \qquad \text{B-1.4-2}$$

$$a_n = \frac{(1+i)^n-1}{i(1+i)^n} \qquad \text{B-1.2-7}$$

$$e_a = [(1+e_r)(1+e_i)]-1 \qquad \text{B-1.3-2}$$

and

e_a = apparent annual escalation rate
e_r = real annual escalation rate
e_i = annual inflation rate
i = annual discount rate
n = number of years.

The inital monetary amount that is multiplied by the factor $\underline{L_n}$ is stated in the beginning of first year dollars, even though all transactions are made at the end of their respective years.

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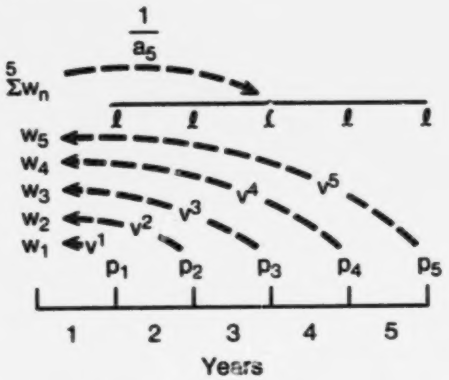
Example B-1-8. Determine the levelized value $\underline{\ell}$ of a 5 year series of payments that escalate at an annual apparent escalation rate of 6.5%. The annual discount rate is 10%, and the estimated cost of a payment at the beginning of the first year is $100. In order to better understand the meaning of levelization, do not use the levelization factor of Equation B-1.4-1.

The time diagram would be



$\frac{1}{a_5}$
$\sum^{5} w_n$
ℓ ℓ ℓ ℓ ℓ
w_5
w_4
w_3
w_2
w_1
v^1
v^2
v^3
v^4
v^5
p_1 p_2 p_3 p_4 p_5
1 2 3 4 5
Years

The payment, $\underline{p_n}$, in year $\underline{n}$ would be

$$p_n = 100\,(1+e_a)^n$$

The present value of that payment, $\underline{w_n}$, would be

$$w_n = p_n v^n$$

The levelized value would be

$$\ell = \frac{w_1 + w_2 + w_3 + w_4 + w_5}{a_5}$$

Thus:

Year	$(1+e_a)^n$	p_n	w_n
1	1.065	$106.50	$96.81
2	1.134	113.40	93.69
3	1.208	120.80	90.72
4	1.286	128.60	87.86
5	1.370	137.00	85.08
		$\Sigma w_n =$	454.16

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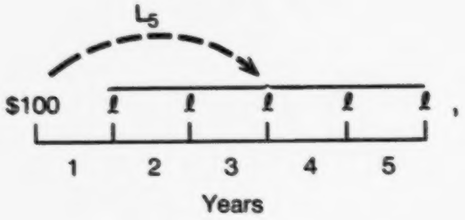
$$\ell = \frac{454.16}{a_5}$$

$$= \underline{\underline{\$119.80}}$$

Example B-1-9. Repeat Example B-1-8, except use the levelization factor of Equation B-1.4-1.

The use of the levelization factor allows a relatively simple time diagram.



From Equation B-1.4-2,

$$k = \frac{1+e_a}{1+i}$$

$$= \frac{1+0.065}{1+0.10}$$

$$= 0.9682$$

and substituting in Equation B-1.4-1

$$L_n = \frac{k\,(1-k^n)}{a_n\,(1-k)}$$

$$= \frac{0.9682\,[1-(0.9682)^5]}{3.791\,(1-0.9682)}$$

$$= 1.198$$

$$\text{and } \ell = \$100\,(1.198)$$

$$= \underline{\underline{\$119.80}}$$

which agrees with the result of Example B-1-8.

Chapter B-2

ELECTRIC UTILITY PARAMETERS AND REVENUE REQUIREMENT ECONOMIC ANALYSIS

B-2.1 INTRODUCTION

Chapter B-1 presented the financial mathematics necessary for the economic evaluation methodology in the Technical Assessment Guide. This chapter develops that methodology.

The revenue requirement method is used to evaluate alternatives at the Electric Power Research Institute and is the method generally used in the electric utility industry for the economic comparison of alternatives.

The electric utility industry has at least five characteristics that set it apart from most other industries:

1. It is capital intensive and for some utilities, over half of the revenue from the sale of electricity is allocated to pay obligations that are related to capital investment.
2. The investment items generally are long-lived, often in the 30 to 50 year range.
3. It has a relatively uniform flow of revenue dollars on an annual basis.
4. It is required to supply product demand and usage as determined by the customers of its service territory rather than to select the markets that it will enter.
5. It is regulated by government agencies and is mandated to provide reliable, low-cost electricity in an environmentally acceptable manner.

In the business community, there are several methods for making economic analyses of alternate choices. These include:

- Specialized methodologies for particular industries, especially industries with relatively short-lived plant items or with rapid technological obsolence

- Discounted cash flow
- Return on investment
- Cost/benefit ratio
- Payback period
- Revenue requirement

The revenue requirement methodology is generally regarded as most appropriate for the electric utility industry. In this approach, the revenue required to sustain a given alternative is determined and compared to a similarly derived revenue requirement of other alternatives. This method determines the revenue required from the ratepayer and therefore is consistent with the principle of ensuring electricity supply at the lowest possible price since it allows a determination of the lowest revenue required from ratepayers (with regulatory definition of adequate return to investors) rather than to maximize return to investors. The method does not determine the cost or price of electricity necessary for ratemaking purposes since that value is determined on a different basis that must take into account the historical and existing financial condition of the electric utility.

B-2.2 REVENUE REQUIREMENT

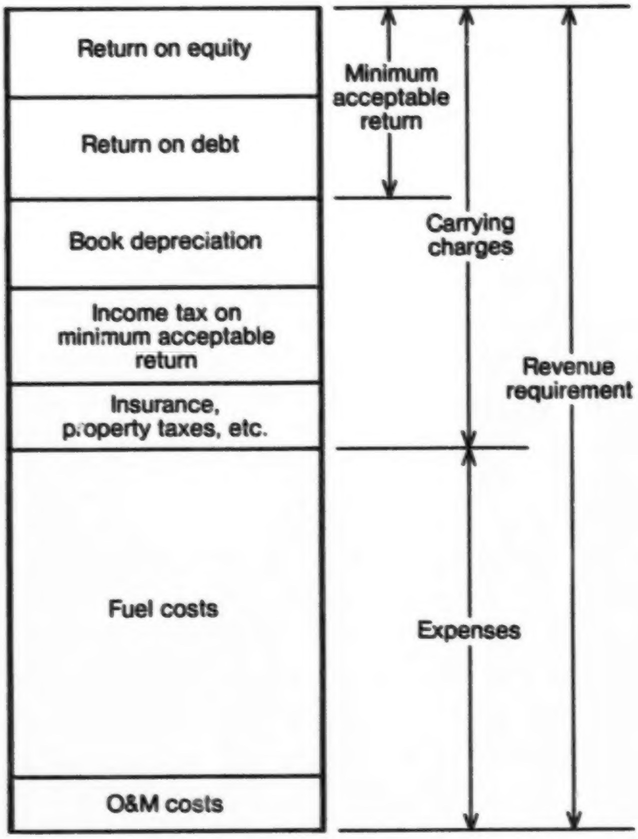
The revenue requirement is the amount of revenue that must be collected from customers to compensate a utility for all expenditures associated with the implementation of an alternative decision involving money. In the long run, revenue must pay for all of the costs of doing business as defined by regulatory action.

Exhibit B-2-1 illustrates that revenue requirements include two components, carrying charges (often referred to as fixed charges) and expenses. Carrying charges are a general designation for charges that are related to capital investment. They constitute the obligation inherent in an investment decision and are incurred regardless of how much the particular investment is used or may be used. Expenses generally are made to cover the way in which a facility is operated or maintained and include fuel, operating, and maintenance costs.

[redacted]

Exhibit B-2-1

REVENUE CATEGORIES FOR THE REVENUE REQUIREMENT METHOD OF ECONOMIC COMPARISON


Return on equity
Return on debt
Book depreciation
Income tax on minimum acceptable return
Insurance, property taxes, etc.
Fuel costs
O&M costs
Minimum acceptable return
Carrying charges
Revenue requirement
Expenses

The terms carrying charges and expenses are sometimes used to define slightly different quantities throughout the industry both by engineering economists and by accountants. In order to provide a general methodology that can be applied by EPRI to the various sectors of the industry, the definitions shown on Exhibit B-2-1 have been established.

Expenses are sometimes referred to as operating costs and in accordance with established ratemaking practices, are paid for directly from revenue. Thus, a dollar of expense is equal to and requires a dollar of revenue. Expenses usually are made for goods and services that are utilized in a short period of time, usually one year or less. Generally, at least 60% of the total revenue collected annually by an electric utility pays the expenses.

The remaining revenue goes to pay the carrying charge obligation associated with an investment (an investment is sometimes referred to as a capital item or a plant item). The installed cost of an investment is not taken from revenue when incurred because (1) this would require present customers to pay for items that would be used to supply customers as much as 60 years into the future and (2) from a practical matter, the relatively uniform flow of revenue dollars would not be adequate for a pay-as-you-go construction program that may have widely varying monetary requirements through time.

The money to cover the total capital requirement of an investment comes from new financing through the sale of bonds and debentures referred to as "debt financing," and for investor-owned utilities from the sale of common and preferred stock, referred to as "equity financing." An analysis of the relative amounts of debt and equity money is beyond the scope of the Technical Assessment Guide, but most investor-owned utilities maintain debt ratios (ratio of debt financing to total financing) in the neighborhood of 50%.

The return, or the money that the utility must pay to investors for the use of both debt and equity money, is a component of the revenue requirement and is part of the obligation associated with an investment. The other components of carrying charges include book depreciation (the annual charge to repay the original amount obtained from investors) and Federal and local income taxes. Local property taxes and insurance are often included as carrying charges and are done so here.

As outlined in Exhibit B-2-1, the breakdown of revenue requirements is as follows:

Table B-2-1

REVENUE REQUIREMENTS

Carrying Charges	*Expenses*
Return on debt	Fuel
Return on equity(1)	Operating
Book depreciation	Maintenance
Income taxes	
Local property taxes	
Insurance	

(1) Dividend paid out

The revenue requirement technique requires the determination of all applicable annual carrying charges and expenses for each year over the life of the plant.

Exhibit B-2-1 also shows a segment entitled "Minimum Acceptable Return" and is equal to return on debt and return on equity. This is the lowest amount that investors will accept in order to make available the funds needed by the utility for the investment.

The revenue requirement of an alternative is the discrete charges associated with that alternative and is used for comparing that alternative with other alternatives.

B-2.3 NATURE OF CARRYING CHARGES

Carrying charges are an obligation incurred when the plant is placed in service, and they remain an obligation until the plant is retired at the end of its life. The only way to avoid a carrying charge obligation is to not commit funds for the plant investment, because once the investment is made, the carrying charge must be collected as revenue regardless of how much or how little the plant is actually used until the plant is fully depreciated.

Existing plant investments are sometimes referred to as sunk costs because they result from prior decisions and, except for any portion that may be recovered through salvage, cannot be affected by a current course of action. Thus, the retirement of a plant item ordinarily will not affect the presence of carrying charges as revenue requirements. Conversely, an expense usually can be terminated simply by terminating the service provided.

On the other hand, after a capital investment is made, the resulting carrying charge level will not change unless there is a change in the tax laws that would specifically affect that investment or unless there is a change in the cost of equity (common and preferred stock) money. A capital investment, once made, is not subject to further inflation.

B-2.4 DESCRIPTION OF CARRYING CHARGES

The following description of the components of the carrying charge is provided for information purposes. The carrying charges that are to be used for illustrative purposes in the TAG are contained in the tables included in Chapter B-3 of the yellow pages. Current values to be used in all economic evaluations performed for EPRI are found in Appendix A of the white pages.

B-2.4.1. Depreciation

Depreciation is the annual charge against revenue used to repay the original amount obtained from debt holders. Depreciation also reflects the fact that when plant is used it wears out and according to regulatory practice, ratepayers pay for this.

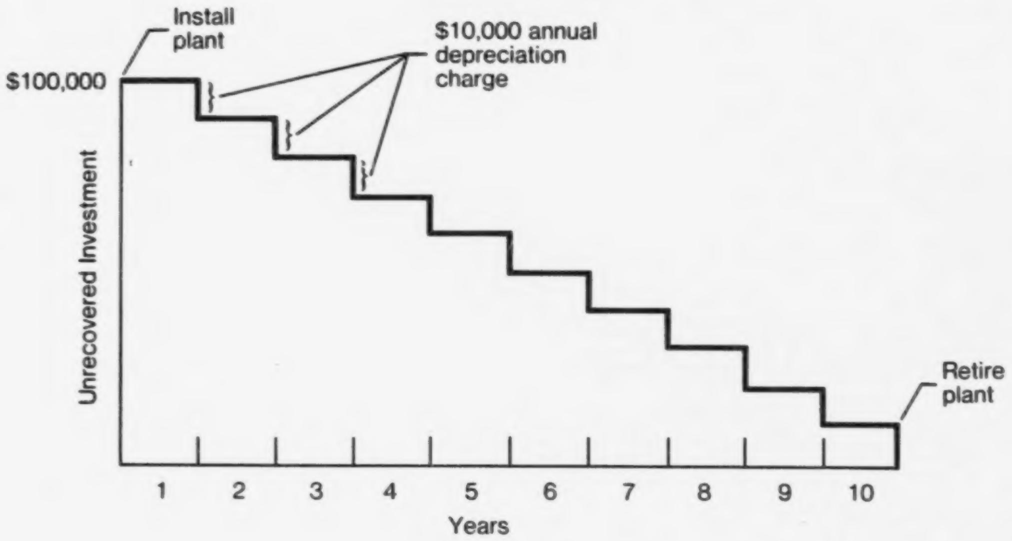
There are many methods of determining the depreciation charge. Some industries use the sinking fund method in which depreciation funds are set aside in an interest bearing account so that when the plant is retired at the end of its life, the sinking fund account will have funds equal to the amount of the original investment.

The electric utility industry uses the straight line method for book depreciation. Using this technique, an annual charge is made against revenue that is equal to the original cost of the investment divided by the expected years of life. Book depreciation could be used to repay the debt holders, but in an expanding utility, more than likely it would be reinvested in new plant items. The TAG assumes that when a plant item is retired, the cost of removal will equal the salvage or junk value resulting in zero salvage. If the net salvage is not zero and is significant, such as the case of a nuclear plant decommissioning, the Planning and Evaluation Division should be consulted.

In fact, the total investments of a utility are included in the "plant account" which is somewhat analogous to the rate base. The book depreciation charge is a percentage of the composite, or weighted, average life of all plant items in the plant account. However, in order to reflect discrete plant lives, unit accounting procedures usually are assumed in an engineering economic analysis. Each plant investment is assumed to be in a separate account and the depreciation rate based upon the individual life of the plant investment rather than the composite life of all investments in the plant account. Note that the revenue requirement methodology takes a rudimentary and very reduced version of an actual accounting system and, therefore, cannot be used for comparison with actual systems nor used for accounting type problems.

Example 2-1: Determine the annual book depreciation charge for $100,000 plant item with a ten-year life assuming straight line depreciation. A time diagram will be used to illustrate.

$$\text{Annual book depreciation} = \frac{\$100{,}000}{10\text{ years}} = \$10{,}000/\text{year}$$



This diagram is different from those used in early examples since unrecovered investment is now the ordinate. It will be found to be more useful in the types of problems encountered in the engineering economics field. Note that at the end of each year the depreciation charge reduces the outstanding investment for the following year. This has the effect of reducing the carrying charge in each succeeding year.

B-2.4.2 Return on Investment

Return on investment is the annual amount that investors are paid for the use of their money. Return on investment is often called the "cost of money." For illustrative purposes in Section B of this Guide (yellow pages), the annual cost of money is assumed to be ten percent. Thus, for every dollar of outstanding investment, a utility would be allowed to collect 10¢ in revenue in order to compensate investors for the use of their money. The actual return found in industry may vary from time to time, and current levels to be used in all economic evaluations performed for EPRI are reflected in the Tables found in Appendix A of the white pages.

Return applies only to funds that the company currently uses. It is not an obligation on investment capital that was raised in the past and has since been removed through the depreciation charge. It was stated earlier that depreciation funds, using standard utility accounting practices, if not used to pay back investors, can be reinvested in new plant items. Therefore, the return obligation on an investment is based on the undepreciated investment or the money remaining in the investment account after depreciation has been deducted. If reinvested, the new plant item is responsible for earning a return on the investors' money.

Example B-2-2: Using the $100,000, 10-year plant item of Example B-2-1, determine the annual return on investment assuming a cost of money of 10%. Based on a $10,000 annual book depreciation charge, the unrecovered investment each year is as shown in column A (below), and the annual return is 10% of that unrecovered investment as shown in column B payable at the end of the year.

[redacted]

Year	Column A Unrecovered Investment[1]	Column B Annual Return
1	$100,000	$10,000
2	90,000	9,000
3	80,000	8,000
4	70,000	7,000
5	60,000	6,000
6	50,000	5,000
7	40,000	4,000
8	30,000	3,000
9	20,000	2,000
10	10,000	1,000

[1] Beginning of year

Investors' money comes to the utility in two forms, debt and equity. Debt money is acquired by mortgaging a portion of the physical assets of the company (mortgage bond) or by issuing an "IOU" without the physical assets of the utility used as collateral (debenture). In either case, the money carries an obligation to pay a stated return regardless of whatever else the company would like to do with the money. Debt money is the most secure form of investment.

Equity money is acquired by selling ownership in the business through issuing either preferred stock or common stock. The important points of debt and equity financing are summarized in the following table:

Table B-2-1

UTILITY SECURITIES

OFFERING	TYPE	LIFE	OBLIGATION TO PAY RETURN	RELATIVE LEVEL OF RETURN	VOTE @ ANNUAL MTG	LIQUIDATION PRIORITY
1st Mortgage Bond	Mortgage on Physical Assets	30-35 yrs.	First	Lowest (Fixed)	No	First
Debenture	Unsecured Obligation	10-50 yrs.	Second	Second Lowest (Fixed)	No	Second
Preferred Stock	Part Owner of Company	Usually Perpetual	Third	Second Highest (Usually Fixed)	Sometimes	Third
Common Stock	Part Owner of Company	Perpetual	Last	Highest (Variable)	Yes	Last

The following economic parameters are used to establish carrying charge levels for the examples given in this section of the Guide. Actual economic parameters are found in Appendix A of the white pages.

	Capitalization Ratio[1]	*Annual Cost*[2]	*Annual Return*[3]
Debt	50%	8.0%	4.0%
Preferred stock	15	8.5	1.3
Common stock	35	13.5	4.7
Total return (weighted cost of capital)			10.0%

[1] The capitalization ratio for each type of security is the amount of that security divided by the total amount of all securities.

[2] Based on a perceived annual inflation rate of 6% (see Sect. 2.7).

[3] Annual return equals capitalization ratio times annual cost.

B-2.4.3 Income Taxes

Income taxes are computed by multiplying the tax rate by the difference between total revenue and all deductible expenditures. This is the exact method used by an individual tax payer when filing his annual income tax return.

For the examples in the TAG, the income tax rate is derived from a 46 percent Federal income tax rate and an assumed 6 percent state income tax rate. Since state income tax is deductible for Federal income tax purposes, the total tax rate; $\underline{t}$ is

$$\begin{aligned} t &= 0.06+(1-0.06)(0.46) \\ &= \underline{\underline{0.4924}} \end{aligned} \qquad \text{B-2.4.3-1}$$

The total income tax rate as used in this Guide for illustrative purposes will be rounded to 0.50.

In a regulated utility, most of the expenditures that constitute revenue requirements such as operating and maintenance charges, fuel costs and return on debt are deductible for income tax purposes, and therefore have no tax obligation. The tax laws also permit a deduction for cost recovery for tax purposes which is similar in nature to the book depreciation entry for ratemaking purposes. The Federal government's methods of determining the cost recovery tax deduction usually will result in a shorter recovery period and, in early years may allow a greater deduction than that which would have been permitted using a straight-line technique over the same recovery period.

In 1954, the United States Internal Revenue Code was amended to allow tax accounting procedures that result in greater cost recovery tax deductions in the earlier years than with a straight-line procedure. These greater cost recovery deductions result in a modification of the time in which income taxes are actually paid compared to the time in which income taxes would have been paid if a straight-line method had been used. In general, tax payments are deferred when any form of accelerated cost recovery is used.

In any year the difference between the income taxes actually paid and the income tax that would have been paid if a straight-line recovery schedule equal to that of book depreciation had been used is called the deferred income tax. In the revenue requirement computation the deferred income tax is equal to the tax rate times the difference between the accelerated tax recovery and the straight-line tax recovery (equal in magnitude to the book depreciation charge) in that year.

The Economic Recovery Tax Act of 1981 provides an Accelerted Cost Recovery System (ACRS) that segregates utility plant into either a 3-, 5-, 10-, or 15-year tax recovery period. For EPRI purposes the simplifying assumption will be made that for all new plant under consideration, the cost recovery schedule will be a 200% declining balance method with a change at an appropriate time to the sum-of-years-digits method.

The following table shows the assignments of utility plant in the Accelerated Cost Recovery System's Tax Recovery Classes.

[redacted]

THREE-YEAR TAX RECOVERY PERIOD

Automobiles
Light Trucks

FIVE-YEAR TAX RECOVERY PERIOD

Nuclear Fuel Assemblies
Office Furniture & Equipment
Computers
Information Systems
Data Handling Equipment
Mining Equipment
Railroad Cars (other than railroad tank cars)
Heavy Trucks

TEN-YEAR TAX RECOVERY PERIOD[1]

Railroad Tank Cars
Qualified Coal Utilitzation Property[2]
Nuclear Production Plant
Combustion Turbine Plant

FIFTEEN-YEAR TAX RECOVERY PERIOD

Steam Production Plant
  (other than qualified coal utilization property included in the 10 year class)
Hydraulic Production Plant
Transmission and distribution

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[1] Electric utility tax accountants generally agree that until appropriate tax rates are promulgated, a 10-year tax recovery period should be used for emerging technologies involving renewable resources.

[2] Qualified coal utilization property includes burners and boilers using coal as their primary fuel which replaced similar equipment that burned oil or natural gas during 1980.

For EPRI purposes it will be generally assumed that all plant has a 30-year useful book life except for hydraulic production plant which is assumed to have a 60-year useful life.

For regulatory purposes there are two methods of handling deferred taxes, "flow through" and "normalization".

In the flow through method the tax deferrals are "flowed through" immediately either to the ratepayers through a decrease in rates or to the stockholders through an increase in equity return.

In the normalization method deferred taxes are accumulated in a reserve account and used as a source of internally generated cash, along with retained equity earnings and book depreciation, to pay for new investment items. This method requires that the utility collect revenue as though income taxes were paid based on straight line tax recovery schedule. This results in the utility having use of the deferred tax funds until the funds are required to pay the tax obligation later in the life of the investment. There is no return obligation as long as the taxes are deferred, and therefore the rate base is reduced by the amount of the accumulated reserve.

The normalization method will be used for EPRI economic studies because it is the tax accounting method most frequently used by electric utilities.

Another tax incentive available to all industry, including electric utilities is the investment tax credit. The investment tax credit, assumed to be 10% in the examples in the TAG, allows a utility to have an immediate reduction in income taxes equal to 10% of the installed cost of a new plant item. The tax reduction is a credit rather than a deferral and is realized in the year that the plant item goes in service.

Thus, a $1,000,000 plant item with a 10% investment tax credit would allow an immediate reduction in income tax payments of $100,000. The treatment of the investment tax credit is also subject to the "flow through" versus "normalized" considerations presented above for accelerated depreciation. In the TAG, the investment tax credit is normalized along with the deferred income taxes. The deferred income taxes and the investment tax credit are called, collectively, tax preferences.

The inclusion of the effect of tax preferences in an economic analysis is a judgmental decision. Earlier editions of the TAG have recommended that the tax preferences be excluded from long-term analyses (service date to be 30 or more years into the future) because of the history of frequent changes of the Internal Revenue Code. The earlier editions did state, however, that it may be appropriate to include them in near-term studies.

Because it now appears that tax preferences are likely to continue indefinitely, it is currently recommended that tax preferences be included in economic analyses performed at EPRI, although it may be entirely appropriate to make an analysis both with and without the tax preferences to show the future consequences to a candidate technology if the revenue code is substantially revised. For convenience, the illustrative tables appended to Chapter B-3 of the yellow pages and Appendix A of the white pages that are to be used in economic evaluations performed for EPRI, include tables both with and without the tax preferences.

While a government owned utility system does not pay income taxes, a payment in lieu of income taxes is often included in carrying charges. Accordingly, the carrying charge tables in Appendix A (white pages) and those appended to Chapter B-3 for illustrative purposes (yellow pages) both with or without the tax preferences can be used for all types of utility systems.

B-2.5 PROPERTY TAXES AND INSURANCE

In this Guide, property taxes and insurance are assumed to be levelized at 2% of the installed cost of an investment item and are included as a carrying charge.

B-2.6 DISCOUNT RATE

The discount rate to be used in present value calculations is related to the weighted cost of capital. Most utilities use a discount rate equal to the weighted cost of capital, but some use an "after tax cost" equal to the weighted cost of capital less the tax rate times the debt return. Neither method is completely appropriate under all circumstances for all electric utilities. A discount rate equal to the weighted cost of capital has been selected for use at EPRI because of its more general use in the electric utility industry.

For illustrative purposes in the yellow pages, the weighted cost of capital is assumed to be 10 percent and is reflected in the tables appended to Chapter B-3. The actual weighted cost of capital to be used in all economic evaluations performed for EPRI is reflected in Appendix A of the white pages.

B-2.7 FURTHER DISCUSSION OF ESCALATION AND INFLATION

Section B-1.3 introduced the general concepts of escalation and inflation and Section B-2.4.2 discussed return on investment and cost of money. This section will present the effect of escalation and inflation on the cost of money.

The discount rate is dependent upon the current money market which has experienced a general increase in inflation for a number of years. In general,

$$(1+i)^n = [(1+c)(1+e_i)]^n$$

$$i = [(1+c)(1+e_i)] - 1 \qquad \text{B-2.7-2}$$

where i = today's discount rate that reflects the current money market
c = weighted cost of capital in the absence of inflation.
e_i = inflation rate
n = number of years

If the inflation rate e_i is 6%, and the discount rate i is 10%, using Equation B-2.7-2, the weighted cost of capital in the absence of inflation is about 3.77%. (Actual factors to be used in all economic evaluations performed for EPRI may be found in Appendix A of the white pages.) If economic studies are made, in constant dollars, without the effect of inflation, the discount rate should be the weighted cost of capital in the absence of inflation. On the other hand, if an inflation rate other than 6% is used, the discount rate must be adjusted accordingly.

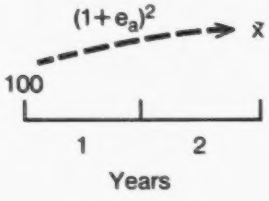
Example B-2-3: If a certain expenditure is $100 now, the annual real escalation rate is 0.8% and the annual inflation rate is 12%, would there be an advantage in making the expenditure now instead of two years hence when it would be required? Note that this is a repeat of Example B-1-7, but assume that inflation is 12%, double the rate of the earlier example.

In this case, using Equation B-1.3-2 the apparent escalation rate would be

$$e_a = [(1+e_r)(1+e_i)] - 1 \qquad \text{B-1.3-2}$$

$$e_a = [(1+0.008)(1+0.12)] - 1$$

$$= \underline{\underline{12.896\%}}$$



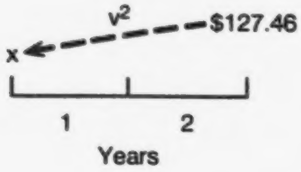
$$x = \$100\,(1.12896)^2$$

$$= \underline{\underline{\$127.46}}$$

In this case \$100 today will escalate to \$127.46 in two years.

But the higher inflation rate will impact the discount rate. Using Equation B-2.7-2, and assuming that the 10% discount rate with a 6% inflation rate is based on a 3.8% discount rate in the absence of inflation,

$$\begin{aligned} i &= [(1+c)(1+e_i)] - 1 \qquad \text{B-2.7-2} \\ &= [(1+0.038)(1+0.12)] - 1 \\ &= \underline{\underline{16.256\%}} \end{aligned}$$



$$\begin{aligned} x &= \$127.46\left(\frac{1}{(1+0.16256)^2}\right) \\ &= \underline{\underline{\$94.31}} \end{aligned}$$

Compare this answer to that of Example B-1-7. Even under severe inflationary conditions, it would not be economically advantageous to make the expenditure two years early because of the impact of the inflation rate on the discount rate. Advance purchases can be justified only if the real escalation rate is greater than the discount rate in the absence of inflation.

In general, expenses and the capital cost of investment items are subject to inflation, while annual carrying charges are not. Thus, once a capital investment is made, the resulting year-by-year carrying charges are fixed, and in fact will vary with time according to preset schedules. A capital investment is regarded by many as a "hedge" against inflation.

B-2.8 REGULATION AND RATE MAKING

The revenue requirement comparison assumes that whatever revenue would be required to sustain an alternative would be available. But, in practice, if revenue is not adequate, the stockholders (equity return) will be affected and income tax payments will decrease.

To illustrate, assume that the $100 expenditure of Example 2-3 that would not be required for two years was an expense. If the $100 expense was made today, instead of two years hence, and there was no offsetting revenue to cover the $100 revenue requirement, both equity return and income taxes for the total company would be reduced as follows:

$$\begin{aligned} \text{Reduced equity return} &= \$100\,(1-t) \\ \text{Reduced income taxes} &= \$100\,(t) \\ \text{where } t &= \text{income tax rate.} \end{aligned}$$

Thus, at a 50% tax rate, equity return and income taxes would each be reduced by $50 to pay for the $100 expense item if there were no offsetting revenue.

B-2.9 OCCURRENCE OF PAYMENTS

For convenience in making economic studies, it is assumed that all investments are made at the beginning (January 1) of a year based on cost estimates referenced to December 31 of the previous year and all carrying charges and, unless otherwise stated, all expenses are made at the end of a year.

Chapter B-3

ENGINEERING ECONOMICS METHODOLOGY

B-3.1 INTRODUCTION

Earlier chapters of the yellow pages presented the concepts of present value and inflation and developed the revenue requirement method. This chapter will combine the work thus far and demonstrate the use of the illustrative tables that are appended to this chapter. These appended tables are similar to those in Appendix A of the white pages. Appendix A reflects the current values to be used in all economic evaluations performed for EPRI.

Tables I, II, and III are to be used for current-dollar analysis where the effect of inflation is to be included. Tables IV, V, and VI are similar except that they are to be used for constant-dollar analysis where the effect of inflation is not included. The discount rate in Tables IV, V, and VI has been modified in accordance with Section B-2.7.

B-3.2 ECONOMIC PARAMETERS

The economic parameters used are shown on the first page of the Tables for Illustrative Purposes that are appended to this chapter and the tables of Appendix A of the white pages.

B-3.3 TABLES I AND IV

Table I is a list of the $\underline{v}^n$ and $\underline{a}_n$ factors for the stated discount rate and inflation rate and is to be used for current-dollar analysis if there is no real escalation. Table IV is similar to Table I except that it is to be used for constant-dollar analysis where the effect of inflation is not included.

B-3.4 TABLES II AND V

Table II is a list of the $\underline{L}_n$ factors for noncarrying charge expenditures for current-dollar analysis using the stated discount rate and inflation rate and based on the real escalation rates as indicated in the table. Table V is similar to Table II except that it is to be used for constant-dollar analysis where the effect of inflation is not included.

B-3.5 TABLES III AND VI

Tables III, developed in the following pages of this chapter, present carrying charge information for several classes of plant for current-dollar analysis. Tables VI are similar to Tables III except that they are for constant-dollar analysis where the effect of inflation is not included.

B-3.6 YEAR-BY-YEAR CARRYING CHARGES

Section B-2.2 defined the revenue requirement of an alternative as a series of year-by-year carrying charges and expenses spread over the life of the alternative.

The year-by-year carrying charges for several types of plant items employing the stated economic factors have been calculated using a computer program.

For example, using a 10% cost of money the year-by-year carrying charge factors are shown below for a plant item having a 2% local property tax rate (based on the original cost of the unit), a 30-year book life, and a 10-year tax recovery period with a 10% investment tax credit and using a combination of 200% Declining Balance - Sum-of-the-Years-Digits tax recovery as appropriate with normalization accounting (tax preferences). The carrying charge factors are expressed as a fraction of the total capital requirement (see Chapter 3). These factors are multiplied by the original investment to determine the year-by-year carrying charges.

TABLE B-3-1

Year By Year Carrying Charge Factors[1]

Year	Yr/Yr CC Factor	Year	Yr/Yr CC Factor
1	0.191	16	0.079
2	0.181	17	0.077
3	0.164	18	0.074
4	0.149	19	0.072
5	0.136	20	0.070
6	0.124	21	0.068
7	0.114	22	0.066
8	0.105	23	0.064
9	0.098	24	0.062
10	0.093	25	0.059
11	0.089	26	0.057
12	0.087	27	0.055
13	0.085	28	0.053
14	0.083	29	0.051
15	0.081	30	0.049

[1] For plant with 10-year tax recovery period and 30-year book life. Cost of money is 10%/year.

The year-by-year carrying charge diminishes in each succeeding year because of the effect of capital recovery through book depreciation.

B-3.7 PRESENT VALUE AND LEVELIZED CARRYING CHARGES OVER BOOK LIFE

An array of numbers through time is difficult to compare with similar series derived for other alternatives, simply because of the multiplicity of numbers. For this reason, present value arithmetic is used to provide a single number for comparative purposes. The resulting present value of carrying charges ($V_{m,n}$) is a a number equal to the sum of the present value of each of the year-by-year carrying charges.

[redacted]

$$V_{m,n} = CC_1v^1 + CC_2v^2 + \cdots + CC_nv^n \qquad \text{B-3.7-1}$$

where CC_1 is the carrying charge in the first year, etc., up to the n^{th} year book life, $\underline{v}^1$, etc., is the appropriate present worth factor from appended Table I and $\underline{m}$ is the tax recovery period. Using the technique demonstrated in Example B-1-5, the levelized carrying charge $P_{m,n}$ may be calculated by dividing $V_{m,n}$ by $\underline{a_n}$ where $\underline{n}$ is the book life,

$$P_{m,n} = \frac{V_{m,n}}{a_n} \qquad \text{B-3.7-2}$$

Example B-3-1. Using Equations B-3.7-1 and B-3.7-2 and the carrying charges of the plant item shown in Table B-3-1, determine $V_{m,n}$ and $P_{m,n}$ The $\underline{v^n}$ and $\underline{a_n}$ factors that are used are found in appended Table I.

TABLE B-3-2

Cumulative PVCC Factors(1)

Year	Yr/Yr CC(2)	Cumulative PVCC(3)	Levelized CC(4)	Year	Yr/Yr CC(2)	Cumulative PVCC(3)	Levelized CC(4)
1	0.191	0.173	0.191	16	0.079	1.029	0.132
2	0.181	0.323	0.186	17	0.077	1.044	0.130
3	0.164	0.446	0.179	18	0.074	1.058	0.129
4	0.149	0.548	0.173	19	0.072	1.069	0.128
5	0.136	0.632	0.167	20	0.070	1.080	0.127
6	0.124	0.702	0.161	21	0.068	1.089	0.126
7	0.114	0.760	0.156	22	0.066	1.097	0.125
8	0.105	0.809	0.152	23	0.064	1.104	0.124
9	0.098	0.851	0.148	24	0.062	1.110	0.124
10	0.093	0.887	0.144	25	0.059	1.116	0.123
11	0.089	0.918	0.141	26	0.057	1.121	0.122
12	0.087	0.946	0.139	27	0.055	1.125	0.122
13	0.085	0.971	0.137	28	0.053	1.129	0.121
14	0.083	0.993	0.135	29	0.051	1.132	0.121
15	0.081	1.012	0.133	30	0.049	1.135(5)	0.120(6)

(1) For plant with 10-year tax recovery period and 30-year book life. Cost of money = 10%.

(2) From Table 3-1.

(3) Cumulative PVCC in year f = $\sum_{1}^{f} CC_f v^f$

(4) Levelized CC in year f $= \dfrac{\text{Cumulative PVCC in year f}}{a_f}$

(5) Equals $V_{10,30}$.

(6) Equals $P_{10,30}$.

$$V_{10,30} = 1.135$$

$$P_{10,30} = \frac{V_{10,30}}{a_{30}}$$

$$= \frac{1.135}{9.427}$$

$$= \underline{\underline{0.120}}$$

B-3.8 PRESENT VALUE AND LEVELIZED CARRYING CHARGES OVER SHORT TERM

Using the technique of Equation B-3.7-1, the present value of carrying charges can be computed for the first $\underline{f}$ years of a plant item with a tax recovery period of $\underline{m}$ years and a book life of $\underline{n}$ years. Thus,

$$V_{f,m,n} = CC_1v^1 + CC_2v^2 + \cdots + CC_fv^f \qquad \text{B-3.8-1}$$

$$P_{f,m,n} = \frac{V_{f,m,n}}{a_f} \qquad \text{B-3.8-2}$$

where $f < n$.

Example B-3-2. Using the data of Example 3-1 (Table 3-2), determine the cumulative present value of carrying charges and the levelized annual carrying charge for the first ten years of life.

From Table B-3-2,

$$V_{10,10,30} = 0.887$$

and

$$P_{10,10,30} = \frac{V_{10,10,30}}{a_{10}}$$

$$= \underline{0.144}$$

Thus, the columns headed "Cumulative PVCC" in Table B-3-2 can now be headed $V_{f,m,n}$ after Equation B-3.8-1, and the columns headed "Levelized CC" can now be headed $P_{f,m,n}$ after Equation B-3.8-2.

B-3.9 TABLES III AND VI DESCRIBED

Tables III are a series of tables for current dollar analysis for various classes of plant with and without tax preferences listing the year-by-year carrying charge CC_f, the cumulative present value of carrying charges $V_{f,m,n}$, and the levelized carrying charges $P_{f,m,n}$. Tables VI are similar to Tables III except that they are for constant dollar analysis where the effect of inflation is not included. The following describes the material in each series of tables:

			Tax Preferences	
Class of Plant[1]	*Tax Recovery Class*[2]	*Book Life*	*With Table No.*	*Without Table No.*
Nuclear	10	30	III_N	III_{NO}
Fossil, T&D	15	30	III_F	III_{NO}
Hydro	15	60	III_H	III_{HO}

[1] Electric utility tax accountants generally agree that until appropriate tax rules are promulgated, a 10-year tax recovery period should be used for emerging technologies involving renewable resources.

[2] Based on the Federal tax laws in effect on Dec. 31, 1981.

The material in Table B-3-2 may be found in Table III_N.

B-3.9.1 Computer Programs for Tables I Through VI

The listings in BASIC for the computer programs to generate the material in Tables I through VI may be found at the end of the tables appended to Chapter B-3. The material in Tables I and III (or IV and VI) is calculated by ECONCC and Table II (or V) by ECONLN.

B-3.10 USE LEVELIZED REVENUE REQUIREMENT FOR COMPARISON

The normal economic evaluations performed for EPRI involve a comparison of the present value (or levelized) revenue requirement of alternative technologies. For simplicity and ease in computing busbar energy costs (explained in Section B-3.11) most examples in the TAG use the levelized revenue requirement as opposed to present value of revenue requirements. Depending upon the statement of the data, either may afford a more convenient calculation than the other, although as a rule the levelized calculation is easier to comprehend.

For the illustrations in Chapter B-3, it is assumed that all alternatives have equal reliability, an equal chance of success, and will supply the same function to the electric system. Variations from these assumptions are covered elsewhere in the TAG.

The economics problems that normally would be encountered at EPRI are relatively straightforward and do not require a consideration of complications such as relocation of plant items, the use of surplus items from stock, or the leasing of equipment. If these conditions are encountered, the R&D Planning and Evaluation Division should be consulted. Other complications, such as investments with unequal book lives, and book lives of less than 30 years, are discussed in the sample problems of Chapter B-5.

B-3.11 LEVELIZED REVENUE REQUIREMENT ANALYSIS OVER BOOK LIFE

This section illustrates the use of the levelized revenue requirement to compare alternatives over the book life.

Example B-3-3: A candidate technology (Alternative A), costing $2000/kW in 1000 kilowatt modules, operating at a 50% annual capacity factor with a fuel cost of 2.0¢/kWh in today's dollars, and subject to a 6% inflation rate, is under consideration.

Assuming the successful development of the technology, the prototype would displace an equal amount (energy) of existing oil-fired generation (Alternative B) with fuel costing 4.5¢/kWh in today's dollars, subject to a real escalation rate of 1.6% and a 6% inflation rate. The oil-fired capacity would not be retired but would continue to operate at a lower capacity factor. Assume that the tax recovery period and book life of the candidate technology are 10 years and 30 years respectively and use the carrying charges in appended Table III_N (tax preferences). Make a current-dollar economic evaluation comparison over the 30-year period (book life) to determine the cost advantage of a 1000-kilowatt module of the candidate technology.

Alternative A

The total capital requirement of the candidate technology is

$2000/kW × 1000 kW
or $2,000,000

and will supply

$$1000/\text{kW} \times 8760\ \text{h/yr} \times 0.50\ \text{capacity factor}$$
$$\text{or } 4{,}380{,}000\ \text{kWh/yr}$$

to the system at a fuel cost of

$$4{,}380{,}000\ \text{kWh/yr} \times \$0.02/\text{kWh}$$
$$\text{or } \$87{,}600/\text{yr in today's dollars}$$

Since the fuel cost of the candidate technology is subject to a 6% inflation rate, appended Table I is applicable.

Alternative B

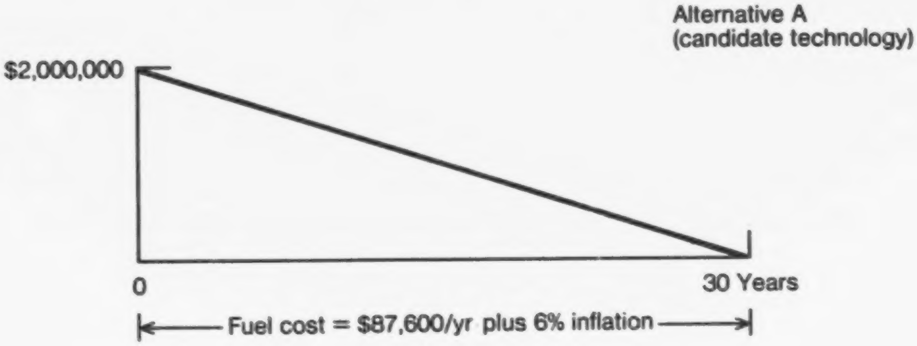
The cost of fuel for the oil-fired generation that is to be displaced would be

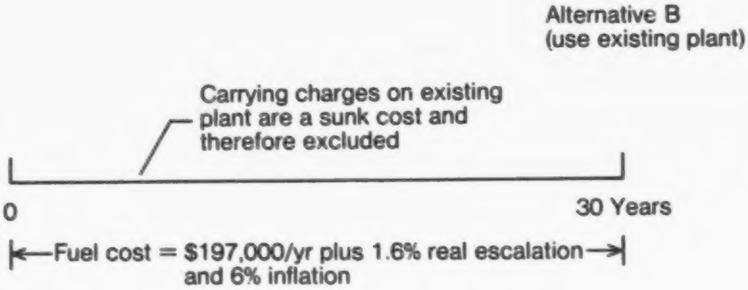
$$4{,}380{,}000\ \text{kWh/yr} \times 0.045/\text{kWh}$$
$$\text{or } \$197{,}000/\text{yr in today's dollars}$$

Appended Tables I and II are applicable since the oil is subject to a 6% inflation rate. The real escalation rate of 1.6% allows the use of the $\underline{L_n}$ factor as appropriate.

The existing investment of the oil-fired technology is a sunk cost (see Section B-2.3) and, therefore, the associated carrying charges are not included in the economic analysis for they do not change. In this example, it is assumed that the remaining physical life of the oil-fired generation is equal to the 30-year book life of the candidate technology. This will eliminate the complication that would arise if equal energy would not be provided by each alternative because the existing plant was retired early. Also, in order to keep the examples simple so as to more easily demonstrate the methodology, the influence of a modified economic dispatch associated with different fuel costs and other operating and maintenance costs has been neglected.

A time diagram will prove helpful to be sure that all applicable costs are properly included. The abscissa is time and the ordinate is unrecovered investment.


Alternative A
(candidate technology)
$2,000,000
0
30 Years
Fuel cost = $87,600/yr plus 6% inflation


Alternative B
(use existing plant)
Carrying charges on existing plant are a sunk cost and therefore excluded
0
30 Years
Fuel cost = $197,000/yr plus 1.6% real escalation and 6% inflation

The Book Life analysis* is as follows:

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*The revenue requirement is calculated over the full 30-year book life. Later in this chapter, the need will be demonstrated for a present value of revenue requirement calculation over only a portion of the book life.

[redacted]

Alternative A

$$\text{LRR}_A = \$2{,}000{,}000\ P_{10,\,30} + \$87{,}600\ L_{30}$$

$$\begin{aligned}\text{LRR}_A &= \$2{,}000{,}000\ (0.120) + \$87{,}600\ (1.886)\\ &= 240{,}000 + 165{,}000\\ &= \underline{\underline{\$405{,}000}}\end{aligned}$$

where L_{30} is based on a 6% inflation rate

The levelized busbar cost is the levelized revenue requirement divided by the energy supplied. In this case

$$\begin{aligned}\text{Levelized busbar cost}_A &= \frac{\$405{,}000}{4{,}380{,}000\ \text{kWh}}\\ &= \$0.0925\ \text{kWh}\\ &= \underline{\underline{92.5\ \text{mills/kWh}}}\end{aligned}$$

Alternative B

$$\text{LRR}_B = \$197{,}000\ L_{30}$$

where L_{30} is based on a 6% inflation rate and a 1.6% real escalation rate

$$\begin{aligned}\text{LRR}_B &= 197{,}000\ (2.331)\\ &= \$459{,}000\\ \text{Levelized busbar cost}_B &= \underline{\underline{104.8\ \text{mills/kWh}}}\end{aligned}$$

To summarize

$$\begin{aligned}\text{Levelized busbar cost}_A &= 92.5\ \text{mills/kWh}\\ \text{Levelized busbar cost}_B &= 104.8\\ \text{Difference} &= 12.3\ \text{mills/kWh}\\ &\quad \underline{\underline{\text{(favoring Alternative A)}}}\end{aligned}$$

[redacted]

The difference in terms of levelized revenue requirements over the 30-year book life is $50,000 per year favoring Alternative A.

The book life analysis of Example B-3-3 is one of the studies that may be necessary to provide meaningful information for the economic evaluation of alternatives in the electric utility industry. However, the book life analysis by itself does not provide enough information since it measures only the long-range consequences of an alternative course of action. It is important to note that the levelized annual revenue requirement is not the cost for any particular year.

B-3.12 YEAR-BY-YEAR REVENUE REQUIREMENT ANALYSIS

The book life analysis, using the present value (levelized) technique, cannot provide the actual array of annual costs over the period of the study and therefore does not indicate the revenue requirement in a specific year in the life of an alternative. Utilities must collect revenue so as to pay the actual year-by-year revenue requirement of an alternative. Thus, if a utility relied solely on present value economic studies, it could select long-term bargains that might seriously jeopardize its near-term financial stability. In addition, the long-term benefits might never materialize because of currently unforeseen changes such as system modifications brought about by technical obsolescence, new regulatory constraints, or urban renewal.

To resolve this shortcoming, other analyses may be in order. One of these is a calculation that shows the actual year-by-year array for each alternative. Such an analysis is called a year-by-year analysis and, as the name implies, is a comparison of the actual revenue requirement for each alternative on a year-by-year basis. Such revenue requirement arrays may be present valued for an overall comparison of alternatives and would be no different over the book life than the present value developed earlier.

The year-by-year analysis is illustrated in the following example:

Example B-3-4. Using the information of Example B-3-3, make a year-by-year analysis.

The time diagrams will not be repeated. The year-by-year charges are given in Table B-3-3.

Table B-3-3

Year-by-Year Charges

Alternative A						*Alternative B*		
	CC							
Year	*Rate*(1)	*Dollars*(2)	$(1+0.06)^n$	*Expense*(3)	*Total RR*	$(1+e_a)^{n(4)}$	*Rev. Req.*(5)	*RR Difference*
1	0.191	$382,000	1.060	$ 93,000	$475,000	1.077	$ 212,000	$ 263,000*
2	0.181	362,000	1.124	98,000	460,000	1.160	229,000	231,000*
3	0.164	328,000	1.191	104,000	432,000	1.249	246,000	186,000*
4	0.149	298,000	1.262	111,000	409,000	1.345	265,000	144,000*
5	0.136	272,000	1.338	117,000	389,000	1.449	285,000	104,000*
6	0.124	248,000	1.419	124,000	372,000	1.560	307,000	65,000*
7	0.114	228,000	1.504	132,000	360,000	1.680	331,000	29,000*
8	0.105	210,000	1.594	140,000	350,000	1.810	357,000	7,000
9	0.098	196,000	1.689	148,000	344,000	1.950	384,000	40,000
10	0.093	186,000	1.791	157,000	343,000	2.099	414,000	71,000
11	0.089	178,000	1.898	166,000	344,000	2.260	445,000	101,000
12	0.087	174,000	2.012	176,000	350,000	2.434	479,000	129,000
13	0.085	170,000	2.133	187,000	357,000	2.622	517,000	160,000
14	0.083	166,000	2.261	198,000	364,000	2.824	556,000	192,000
15	0.081	162,000	2.397	210,000	372,000	3.041	599,000	227,000
16	0.079	158,000	2.540	223,000	381,000	3.275	645,000	264,000
17	0.077	154,000	2.693	236,000	390,000	3.527	695,000	305,000
18	0.074	148,000	2.854	250,000	398,000	3.798	748,000	350,000
19	0.072	144,000	3.026	265,000	409,000	4.091	806,000	397,000
20	0.070	140,000	3.207	281,000	421,000	4.405	868,000	447,000
21	0.068	136,000	3.400	298,000	434,000	4.745	935,000	501,000
22	0.066	132,000	3.603	316,000	448,000	5.110	1,007,000	559,000
23	0.064	128,000	3.820	335,000	463,000	5.503	1,084,000	621,000
24	0.062	124,000	4.049	355,000	479,000	5.926	1,167,000	688,000
25	0.059	118,000	4.292	376,000	494,000	6.382	1,257,000	763,000
26	0.057	114,000	4.550	399,000	513,000	6.874	1,354,000	841,000
27	0.055	110,000	4.822	422,000	532,000	7.403	1,458,000	926,000
28	0.053	106,000	5.112	448,000	554,000	7.972	1,570,000	1,016,000
29	0.051	102,000	5.418	475,000	577,000	8.586	1,691,000	1,114,000
30	0.049	98,000	5.743	503,000	601,000	9.247	1,822,000	1,221,000

(1)From appended Table III_N.

(2)The annual carrying charge dollar amount is obtained by multiplying the carrying charge rate by the $2,000,000 original investment.

(3)The annual expense dollar amount is obtained by multiplying the inflation factor $(1+0.06)^n$ by the $87,600 annual fuel cost in today's dollars.

(4) Where $e_a = 7.696\%$ based on a 6% inflation rate and a 1.6% real escalation rate.

(5)The revenue requirement dollar amount of Alternative B is obtained by multiplying the escalation factor $(1+e_a)^n$ by the $197,000 annual fuel cost in today's dollars.

*Favors Alternative B.

Even though the book life analysis presented in Example B-3-3 showed Alternative A, the candidate technology, to be better by $54,000 in terms of levelized revenue requirements, the year-by-year study of Example B-3-4 shows (Table B-3-3) that Alternative B (continued operation of the oil-fired plant) would provide a lower revenue requirement in each year through the eighth year. Thus, if Alternative A had been selected, it would require $263,000 more revenue in year one, $231,000 more revenue in year two, etc.

While the year-by-year analysis shows the effect on revenue requirements in specific years and, consequently, supplies all of the data necessary for a determination of short-range effects, it is a laborious procedure and produces an array of numbers as an answer.

Often there is no substitute for this detailed study and some portions of the year-by-year analysis are used in the break-even calculations demonstrated in Section B-3.14. In general, however, for the level of detail required for EPRI purposes, a less cumbersome technique that will produce a single number may be appropriate. The next section describes a shortcut approach for the near-term analysis that is called the Short-Term Present Value Analysis.

B-3.13 SHORT-TERM ANALYSIS

As stated in Section B-3.9, the financial factor tables appended to this chapter (Appendix A in the white pages for actual evaluations) include a column showing the cumulative present value of revenue requirements for the first *i* years for a plant item having a stated book life and tax recovery period. For example $V_{10,10,30}$ is the present value of the revenue requirements for the first ten years of life of an investment item having a 10-year tax recovery period and a 30-year book life. It should be noted that $V_{10,10,30}$ is not equal to $(P_{10,30})(a_{10})$ since $P_{10,30}$ is the levelized annual revenue requirement over the 30-year book life of an item with a 10-year recovery period and a 30-year book life. $(P_{10,30})(a_{10})$ is the present value of levelized revenue requirements for a nonspecified 10-year period.

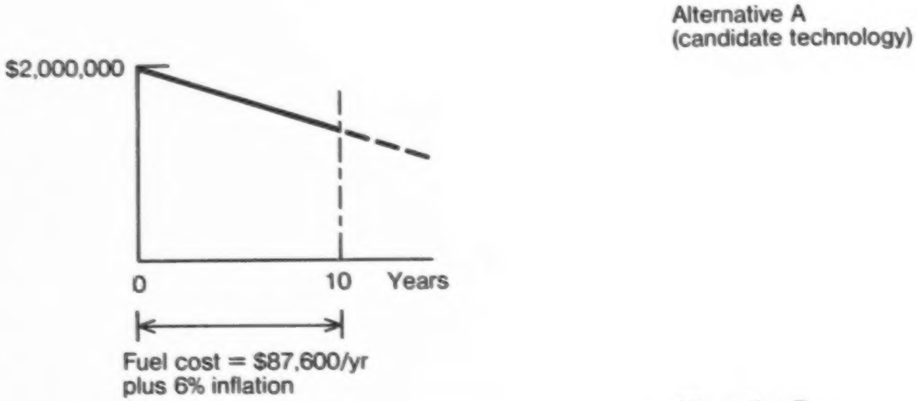
The period or duration of the short-term present value analysis deserves some comment. In today's economic environment, many utilities face a cash shortage brought about by continuing inflation and inadequate rate relief. The analyst must be cognizant of the potential impact of various alternatives on the near-term financial condition of a utility.

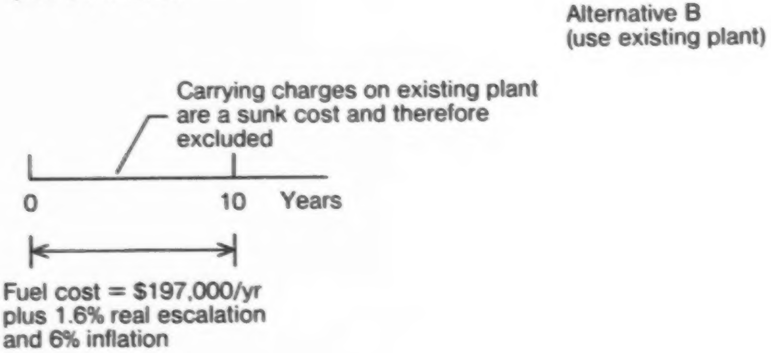
Some utilities have adopted the policy that any alternative that does not show a revenue requirement advantage in the first one-fourth to one-third of its life or that causes significant deficits compared to the other alternatives in the first 10 years of life would not be the proper economic choice. Also, as stated earlier, unforeseen modifications brought about by technical obsolescence, changing regulatory constraints, urban renewal policies, etc., may be such that "long-range" advantages may never materialize.

Accordingly, in the absence of more definitive information, it is recommended that short-term present value analyses at EPRI be computed for a 10-year period.

Example 3-5. Using the information of Example 3-3, perform a short-term present value analysis for the first 10 years.

The time diagram would look like this:


Alternative A
(candidate technology)
$2,000,000
0
10
Years
Fuel cost = $87,600/yr
plus 6% inflation


Alternative B
(use existing plant)
Carrying charges on existing plant are a sunk cost and therefore excluded
0
10
Years
Fuel cost = $197,000/yr
plus 1.6% real escalation
and 6% inflation

[redacted]

$$\text{1st 10-yr LRR}_A = \$2{,}000{,}000\ P_{10,\,10,\,30} + \$87{,}600\ L_{10}$$

where L_{10} is based on a 6% inflation rate

$$\begin{aligned}\text{1st 10-yr LRR}_A &= 2{,}000{,}000\ (0.144) + 87{,}600\ (1.335)\\ &= 288{,}000 + 117{,}000\\ &= \underline{\underline{\$405{,}000}}\end{aligned}$$

$$\begin{aligned}\text{Levelized busbar cost}_A &= \frac{\$405{,}000}{4{,}380{,}000\ \text{kWh}}\\ &= \underline{\underline{92.5\ \text{mills/kWh}}}\end{aligned}$$

$$\text{1st 10-yr LRR}_B = \$197{,}000\ L_{10}$$

where L_{10} is based on a 6% inflation and a 1.6% real escalation rate

$$\begin{aligned}\text{1st 10-yr LRR}_B &= 197{,}000\ (1.451)\\ &= \underline{\underline{\$286{,}000}}\end{aligned}$$

$$\begin{aligned}\text{Levelized busbar cost}_B &= \frac{\$286{,}000}{4{,}380{,}000\ \text{kWh}}\\ &= \underline{\underline{65.3\ \text{mills/kWh}}}\end{aligned}$$

To summarize

$$\begin{aligned}\text{Levelized busbar cost}_A &= 92.5\ \text{mills/kWh}\\ \text{Levelized busbar cost}_B &= \underline{65.3}\\ \text{Difference} &= 27.2\ \text{mills/kWh (favoring Alternative B)}\end{aligned}$$

The difference in terms of levelized revenue requirements over the first 10 years is $119,000 per year favoring Alternative B.

The results of Examples B-3-3, B-3-4, and B-3-5 are summarized:

	Alternative A	*Alternative B*
Book life analysis	Better by $54,000 in terms of LRR (12.3 mills/kWh)	
Year-by-year analysis		Lower revenue requirements in each of 1st 7 years
1st 10-year analysis		Better by $119,000 in terms of LRR (27.2 mills/kWh)

B-3.14 BREAK-EVEN ANALYSIS

An additional analysis that is sometimes used is an offshoot of the short-term present value analysis. The break-even analysis determines the year in which the cumulative present value of revenue requirements of the two alternatives are equal. This usually involves an iterative process and is illustrated below.

Example B-3-6. Using the information of Example B-3-3, determine the break-even point at which the cumulative present value of revenue requirements of the two alternatives are equal.

The iterative or trial-and-error process is based on the equation

$$2{,}000{,}000\, V_{x,\,10,\,30} + 87{,}600\, L_{1x}a_x = 197{,}000\, L_{2x}a_x$$

Substituting,

$$2{,}000{,}000\, V_{x,\,10,\,30} + 87{,}600\, \frac{k_1(1-k_1^x)}{1-k_1} = 197{,}000\, \frac{k_2(1-k_2^x)}{1-k_2}$$

$$\text{where} \quad k_1 = \frac{1.06}{1.10} \quad \text{and} \quad k_2 = \frac{1.07696}{1.10}$$

$$= 0.964 \qquad\qquad = 0.979$$

$$\text{PV factor}_1 = \frac{k_1(1-k_1^x)}{1-k_1}$$

$$\text{PV factor}_2 = \frac{k_2(1-k_2^x)}{1-k_2}$$

In order to accommodate the trial-and-error solution, a tabular form will be used.

		Alternative A				Alternative B	
Year x	$V_{x,\,10,\,30}$	CC	PV Factor	Expense	Total RR	PV Factor	Expense
18	1.058	2,116,000	12.94	1,133,000	3,249,000	14.80	2,916,000
25	1.116	2,232,000	16.07	1,408,000	3,640,000	19.20	3,782,000
23	1.104	2,208,000	15.26	1,337,000	3,545,000	18.01	3,548,000

The break-even point is very close to the twenty-third year.

In the above examples, electric utility management probably would consider Alternative A to not be economically attractive, even though if everything occurred as envisioned by this problem, Alternative A in the thirtieth year alone would have an advantage of over $1,200,000. Of course, not enough of the details have been introduced in this series of examples to allow a logical conclusion to be reached. However, there is a good chance that the laws or regulations that allow the candidate technology to be installed may change before the twenty-third year, the point beyond which Alternative A begins to show an advantage on a cumulative present value basis. Thus, there is a good chance that the candidate technology would have to be modified with the use of additional funds long before the break-even point would be reached. On the other hand, it is possible that the price of oil may escalate much more rapidly than assumed here, thus shortening the break-even point.

This is not to say that development of the candidate technology should not be pursued, since, as stated earlier, not enough information was given to allow a logical conclusion to be reached. EPRI's function is to look ahead and to develop technologies that will meet the future needs of the electric utility industry. Short-term economic considerations are important and may affect research priorities. In spite of the short-term economic advantage of some alternatives, EPRI must also explore those alternatives that at this juncture appear to have only a long-term economic advantage. In any event, the economic consequences of the candidate technology can be determined using the methodology presented in this guide.

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

ECONOMIC PARAMETERS

- FINANCIAL FACTORS

Type of Security	% of Total	Current Dollars		Constant Dollars	
		Cost	Return	Cost	Return
Debt	50%	8.0%	4.0%	1.9	.95
Preferred Stock	15%	8.5%	1.3%	2.3	.34
Common Stock	35%	13.5%	4.7%	7.1	2.48
Total Annual Return (Discount Rate)			10.0%		3.77%

Inflation Rate 6.0%

Federal and State Income

Tax Rate 50 %

Investment Tax Credit 10 %

- TAX AND BOOK LIFE(1)

Plant Class(2)	Tax Recovery(3)	Book Life
Nuclear Fueled Generation	10 years	30 years
Fossil-Fueled Generation Transmission & Distribution	15 years	30 years
Hydro Generation	15 years	60 years

(1) See Section B-2.4.3 for more details

(2) Electric utility tax accountants generally agree that, until appropriate tax rules are promulgated, a 10-year tax life should be used for emerging technologies involving renewable resources.

(3) Based on the federal tax laws in effect on December 31,1981

- USE OF TABLES(1)

	Current Dollars	Constant Dollars
Present worth and levelizing calculations using the factors $\underline{v}^n$ and $\underline{a}_n$	Table I	Table IV
Levelizing calculations using the $\underline{L}_n$ factor	II	V
Carrying charge factors for several classes of electric utility plant with and without tax preferences(2)	III	VI

(1) The user is cautioned that the use of an inflation rate other than 6% requires the calculation of a new discount rate as explained in Section B-2.7.

(2) Property tax and insurance totaling 2% is included in Tables III and VI.

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table I

Current Dollars
(i = 10.0%)

For present worth and levelizing calculations if a 6% inflation rate is used.

f Year	v^f	a_f	f Year	v^f	a_f
1	.9091	0.909	31	.0521	9.479
2	.8264	1.736	32	.0474	9.526
3	.7513	2.487	33	.0431	9.569
4	.6830	3.170	34	.0391	9.609
5	.6209	3.791	35	.0356	9.644
6	.5645	4.355	36	.0323	9.677
7	.5132	4.868	37	.0294	9.706
8	.4665	5.335	38	.0267	9.733
9	.4241	5.759	39	.0243	9.757
10	.3855	6.145	40	.0221	9.779
11	.3505	6.495	41	.0201	9.799
12	.3186	6.814	42	.0183	9.817
13	.2897	7.103	43	.0166	9.834
14	.2633	7.367	44	.0151	9.849
15	.2394	7.606	45	.0137	9.863
16	.2176	7.824	46	.0125	9.875
17	.1978	8.022	47	.0113	9.887
18	.1799	8.201	48	.0103	9.897
19	.1635	8.365	49	.0094	9.906
20	.1486	8.514	50	.0085	9.915
21	.1351	8.649	51	.0077	9.923
22	.1228	8.772	52	.0070	9.930
23	.1117	8.883	53	.0064	9.936
24	.1015	8.985	54	.0058	9.942
25	.0923	9.077	55	.0053	9.947
26	.0839	9.161	56	.0048	9.952
27	.0763	9.237	57	.0044	9.956
28	.0693	9.307	58	.0040	9.960
29	.0630	9.370	59	.0036	9.964
30	.0573	9.427	60	.0033	9.967

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table II

Current Dollars
(i = 10.0%)

Levelized factor $\underline{L_n}$ based on a 6% annual inflation rate and an annual real escalation rate $\underline{e_r}$ as indicated.

$\% e_r$	L_{10}	L_{20}	L_{30}
0.0	1.335	1.629	1.886
0.2	1.349	1.659	1.935
0.4	1.363	1.691	1.986
0.6	1.377	1.723	2.038
0.8	1.392	1.756	2.093
1.0	1.406	1.789	2.149
1.2	1.421	1.824	2.208
1.4	1.436	1.859	2.268
1.6	1.451	1.895	2.331
1.8	1.467	1.932	2.396
2.0	1.482	1.970	2.463
2.2	1.498	2.009	2.533
2.4	1.514	2.048	2.606
2.6	1.530	2.089	2.681
2.8	1.546	2.131	2.759
3.0	1.562	2.174	2.840
4.0	1.647	2.404	3.292
5.0	1.737	2.664	3.838

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Current Dollars

Table III_N

($i = 10.0\%$)

Book Life (n) 30 Years
Tax Recovery (m) 10 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.191	0.173	0.191
2	0.181	0.323	0.186
3	0.164	0.446	0.179
4	0.149	0.548	0.173
5	0.136	0.632	0.167
6	0.124	0.702	0.161
7	0.114	0.760	0.156
8	0.105	0.809	0.152
9	0.098	0.851	0.148
10	0.093	0.887	0.144
11	0.089	0.918	0.141
12	0.087	0.946	0.139
13	0.085	0.971	0.137
14	0.083	0.993	0.135
15	0.081	1.012	0.133
16	0.079	1.029	0.132
17	0.077	1.044	0.130
18	0.074	1.058	0.129
19	0.072	1.069	0.128
20	0.070	1.080	0.127
21	0.068	1.089	0.126
22	0.066	1.097	0.125
23	0.064	1.104	0.124
24	0.062	1.110	0.124
25	0.059	1.116	0.123
26	0.057	1.121	0.122
27	0.055	1.125	0.122
28	0.053	1.129	0.121
29	0.051	1.132	0.121
30	0.049	1.135	0.120

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_F

Current Dollars
(i = 10.0%)

Book Life (n) 30 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.191	0.173	0.191
2	0.183	0.325	0.187
3	0.171	0.453	0.182
4	0.159	0.562	0.177
5	0.149	0.654	0.173
6	0.138	0.732	0.168
7	0.129	0.799	0.164
8	0.121	0.855	0.160
9	0.113	0.903	0.157
10	0.106	0.944	0.154
11	0.100	0.978	0.151
12	0.094	1.009	0.148
13	0.090	1.035	0.146
14	0.085	1.057	0.143
15	0.082	1.077	0.142
16	0.079	1.094	0.140
17	0.077	1.109	0.138
18	0.074	1.122	0.137
19	0.072	1.134	0.136
20	0.070	1.144	0.134
21	0.068	1.154	0.133
22	0.066	1.162	0.132
23	0.064	1.169	0.132
24	0.062	1.175	0.131
25	0.059	1.181	0.130
26	0.057	1.185	0.129
27	0.055	1.190	0.129
28	0.053	1.193	0.128
29	0.051	1.197	0.128
30	0.049	1.199	0.127

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_H

Current Dollars
($i = 10.0\%$)

Book Life (n) 60Years
Tax Recovery (m) 15Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{t, m, n}$)	Levelized Carrying Charge ($P_{t, m, n}$)
1	0.177	0.161	0.177
2	0.171	0.302	0.174
3	0.160	0.422	0.170
4	0.149	0.524	0.165
5	0.139	0.611	0.161
6	0.130	0.685	0.157
7	0.122	0.747	0.154
8	0.115	0.801	0.150
9	0.108	0.847	0.147
10	0.102	0.886	0.144
11	0.097	0.920	0.142
12	0.093	0.950	0.139
13	0.089	0.975	0.137
14	0.086	0.998	0.135
15	0.083	1.018	0.134
16	0.081	1.036	0.132
17	0.080	1.052	0.131
18	0.079	1.066	0.130
19	0.078	1.079	0.129
20	0.077	1.090	0.128
21	0.076	1.100	0.127
22	0.075	1.110	0.126
23	0.074	1.118	0.126
24	0.073	1.125	0.125
25	0.072	1.132	0.125
26	0.071	1.138	0.124
27	0.070	1.143	0.124
28	0.069	1.148	0.123
29	0.067	1.152	0.123
30	0.066	1.156	0.123

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_H

Current Dollars
($i = 10.0\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.065	1.159	0.122
32	0.064	1.162	0.122
33	0.063	1.165	0.122
34	0.062	1.167	0.122
35	0.061	1.170	0.121
36	0.060	1.172	0.121
37	0.059	1.173	0.121
38	0.058	1.175	0.121
39	0.057	1.176	0.121
40	0.056	1.177	0.120
41	0.055	1.179	0.120
42	0.054	1.180	0.120
43	0.053	1.180	0.120
44	0.051	1.181	0.120
45	0.050	1.182	0.120
46	0.049	1.182	0.120
47	0.048	1.183	0.120
48	0.047	1.184	0.120
49	0.046	1.184	0.120
50	0.045	1.184	0.119
51	0.044	1.185	0.119
52	0.043	1.185	0.119
53	0.042	1.185	0.119
54	0.041	1.185	0.119
55	0.040	1.186	0.119
56	0.039	1.186	0.119
57	0.038	1.186	0.119
58	0.037	1.186	0.119
59	0.035	1.186	0.119
60	0.034	1.186	0.119

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_{NO}

Current Dollars
(i = 10.0%)

Book Life (n) 30 Years
Tax Recovery (m) 30 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.213	0.194	0.213
2	0.208	0.366	0.211
3	0.203	0.518	0.208
4	0.197	0.653	0.206
5	0.192	0.772	0.204
6	0.187	0.877	0.201
7	0.181	0.971	0.199
8	0.176	1.053	0.197
9	0.171	1.125	0.195
10	0.165	1.189	0.193
11	0.160	1.245	0.192
12	0.155	1.294	0.190
13	0.149	1.337	0.188
14	0.144	1.375	0.187
15	0.139	1.408	0.185
16	0.133	1.438	0.184
17	0.128	1.463	0.182
18	0.123	1.485	0.181
19	0.117	1.504	0.180
20	0.112	1.521	0.179
21	0.107	1.535	0.177
22	0.101	1.548	0.176
23	0.096	1.558	0.175
24	0.091	1.568	0.174
25	0.085	1.575	0.174
26	0.080	1.582	0.173
27	0.075	1.588	0.172
28	0.069	1.593	0.171
29	0.064	1.597	0.170
30	0.059	1.600	0.170

[redacted]

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_{HO}

Current Dollars
($i = 10.0\%$)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.197	0.179	0.197
2	0.194	0.339	0.195
3	0.191	0.483	0.194
4	0.189	0.612	0.193
5	0.186	0.727	0.192
6	0.183	0.831	0.191
7	0.181	0.923	0.190
8	0.178	1.006	0.189
9	0.175	1.081	0.188
10	0.173	1.147	0.187
11	0.170	1.207	0.186
12	0.167	1.260	0.185
13	0.165	1.308	0.184
14	0.162	1.351	0.183
15	0.159	1.389	0.183
16	0.157	1.423	0.182
17	0.154	1.453	0.181
18	0.151	1.481	0.181
19	0.149	1.505	0.180
20	0.146	1.527	0.179
21	0.143	1.546	0.179
22	0.141	1.563	0.178
23	0.138	1.579	0.178
24	0.135	1.592	0.177
25	0.133	1.605	0.177
26	0.130	1.616	0.176
27	0.127	1.625	0.176
28	0.125	1.634	0.176
29	0.122	1.642	0.175
30	0.119	1.648	0.175

[redacted]

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table III_{HO}

Current Dollars
(i = 10.0%)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.117	1.655	0.175
32	0.114	1.660	0.174
33	0.111	1.665	0.174
34	0.109	1.669	0.174
35	0.106	1.673	0.173
36	0.103	1.676	0.173
37	0.101	1.679	0.173
38	0.098	1.682	0.173
39	0.095	1.684	0.173
40	0.093	1.686	0.172
41	0.090	1.688	0.172
42	0.087	1.689	0.172
43	0.085	1.691	0.172
44	0.082	1.692	0.172
45	0.079	1.693	0.172
46	0.077	1.694	0.172
47	0.074	1.695	0.171
48	0.071	1.696	0.171
49	0.069	1.696	0.171
50	0.066	1.697	0.171
51	0.063	1.697	0.171
52	0.061	1.698	0.171
53	0.058	1.698	0.171
54	0.055	1.698	0.171
55	0.053	1.699	0.171
56	0.050	1.699	0.171
57	0.047	1.699	0.171
58	0.045	1.699	0.171
59	0.042	1.700	0.171
60	0.039	1.700	0.171

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table IV

Constant Dollars
($i = 3.77\%$)

For present worth and levelizing calculations if the effect of inflation is not included.

f Year	v^f	a_f	f Year	v^f	a_f
1	.9637	0.964	31	.3175	18.103
2	.9287	1.892	32	.3060	18.409
3	.8949	2.787	33	.2949	18.704
4	.8624	3.650	34	.2842	18.988
5	.8311	4.481	35	.2738	19.262
6	.8009	5.282	36	.2639	19.526
7	.7718	6.053	37	.2543	19.780
8	.7437	6.797	38	.2451	20.025
9	.7167	7.514	39	.2362	20.261
10	.6907	8.205	40	.2276	20.489
11	.6656	8.870	41	.2193	20.708
12	.6414	9.512	42	.2113	20.919
13	.6181	10.130	43	.2037	21.123
14	.5957	10.725	44	.1963	21.319
15	.5740	11.299	45	.1891	21.508
16	.5532	11.852	46	.1823	21.691
17	.5331	12.386	47	.1756	21.866
18	.5137	12.899	48	.1693	22.036
19	.4950	13.394	49	.1631	22.199
20	.4771	13.871	50	.1572	22.356
21	.4597	14.331	51	.1515	22.507
22	.4430	14.774	52	.1460	22.653
23	.4269	15.201	53	.1407	22.794
24	.4114	15.612	54	.1356	22.929
25	.3965	16.009	55	.1306	23.060
26	.3821	16.391	56	.1259	23.186
27	.3682	16.759	57	.1213	23.307
28	.3548	17.114	58	.1169	23.424
29	.3419	17.456	59	.1127	23.537
30	.3295	17.785	60	.1086	23.645

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table V

Constant Dollars
(i = 3.77%)

Levelizing factor $\underline{L_n}$ based on no inflation and an annual real escalation rate $\underline{e_r}$ as indicated.

$\% e_r$	L_{10}	L_{20}	L_{30}
0.0	1.000	1.000	1.000
0.2	1.010	1.019	1.026
0.4	1.021	1.038	1.053
0.6	1.032	1.058	1.081
0.8	1.043	1.078	1.110
1.0	1.053	1.099	1.140
1.2	1.065	1.120	1.171
1.4	1.076	1.141	1.203
1.6	1.087	1.163	1.236
1.8	1.099	1.186	1.271
2.0	1.110	1.209	1.306
2.2	1.122	1.233	1.343
2.4	1.134	1.258	1.382
2.6	1.146	1.283	1.422
2.8	1.158	1.308	1.463
3.0	1.170	1.335	1.506
4.0	1.234	1.476	1.746
5.0	1.301	1.635	2.035

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_N

Constant Dollars
($i = 3.77\%$)

Book Life (n) 30 Years
Tax Recovery (m) 10 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.106	0.102	0.106
2	0.102	0.197	0.104
3	0.095	0.282	0.101
4	0.089	0.359	0.098
5	0.083	0.428	0.095
6	0.079	0.491	0.093
7	0.074	0.548	0.091
8	0.071	0.601	0.088
9	0.068	0.650	0.086
10	0.066	0.695	0.085
11	0.064	0.738	0.083
12	0.063	0.779	0.082
13	0.063	0.817	0.081
14	0.062	0.854	0.080
15	0.061	0.889	0.079
16	0.060	0.922	0.078
17	0.059	0.953	0.077
18	0.058	0.983	0.076
19	0.057	1.012	0.076
20	0.056	1.038	0.075
21	0.055	1.064	0.074
22	0.055	1.088	0.074
23	0.054	1.111	0.073
24	0.053	1.133	0.073
25	0.052	1.153	0.072
26	0.051	1.173	0.072
27	0.050	1.191	0.071
28	0.049	1.209	0.071
29	0.048	1.225	0.070
30	0.048	1.241	0.070

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_F

Constant Dollars
(i = 3.77%)

Book Life (n) 30 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.106	0.102	0.106
2	0.103	0.198	0.105
3	0.098	0.285	0.102
4	0.093	0.366	0.100
5	0.089	0.440	0.098
6	0.085	0.507	0.096
7	0.081	0.569	0.094
8	0.077	0.627	0.092
9	0.074	0.680	0.090
10	0.071	0.729	0.089
11	0.069	0.775	0.087
12	0.066	0.817	0.086
13	0.064	0.857	0.085
14	0.063	0.894	0.083
15	0.061	0.929	0.082
16	0.060	0.962	0.081
17	0.059	0.994	0.080
18	0.058	1.024	0.079
19	0.057	1.052	0.079
20	0.056	1.079	0.078
21	0.055	1.104	0.077
22	0.055	1.129	0.076
23	0.054	1.152	0.076
24	0.053	1.173	0.075
25	0.052	1.194	0.075
26	0.051	1.213	0.074
27	0.050	1.232	0.074
28	0.049	1.249	0.073
29	0.048	1.266	0.073
30	0.048	1.282	0.072

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_H Constant Dollars

(i = 3.77%)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.093	0.089	0.093
2	0.090	0.173	0.091
3	0.086	0.250	0.090
4	0.081	0.320	0.088
5	0.077	0.384	0.086
6	0.073	0.442	0.084
7	0.070	0.496	0.082
8	0.067	0.546	0.080
9	0.064	0.592	0.079
10	0.062	0.635	0.077
11	0.060	0.674	0.076
12	0.058	0.712	0.075
13	0.056	0.746	0.074
14	0.055	0.779	0.073
15	0.054	0.810	0.072
16	0.053	0.839	0.071
17	0.053	0.868	0.070
18	0.052	0.894	0.069
19	0.052	0.920	0.069
20	0.051	0.945	0.068
21	0.051	0.968	0.068
22	0.050	0.990	0.067
23	0.050	1.012	0.067
24	0.050	1.032	0.066
25	0.049	1.052	0.066
26	0.049	1.070	0.065
27	0.048	1.088	0.065
28	0.048	1.105	0.065
29	0.047	1.121	0.064
30	0.047	1.137	0.064

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FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI$_H$

Constant Dollars
($i = 3.77\%$)

Book Life (n) 60 Years
Tax Recovery (m) 15 Years
With Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.047	1.151	0.064
32	0.046	1.166	0.063
33	0.046	1.179	0.063
34	0.045	1.192	0.063
35	0.045	1.204	0.063
36	0.044	1.216	0.062
37	0.044	1.227	0.062
38	0.043	1.238	0.062
39	0.043	1.248	0.062
40	0.043	1.258	0.061
41	0.042	1.267	0.061
42	0.042	1.276	0.061
43	0.041	1.284	0.061
44	0.041	1.292	0.061
45	0.040	1.300	0.060
46	0.040	1.307	0.060
47	0.039	1.314	0.060
48	0.039	1.320	0.060
49	0.039	1.327	0.060
50	0.038	1.333	0.060
51	0.038	1.338	0.059
52	0.037	1.344	0.059
53	0.037	1.349	0.059
54	0.036	1.354	0.059
55	0.036	1.359	0.059
56	0.036	1.363	0.059
57	0.035	1.367	0.059
58	0.035	1.371	0.059
59	0.034	1.375	0.058
60	0.034	1.379	0.058

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_{NO}

Constant Dollars
($i = 3.77\%$)

Book Life (n) 30 Years
Tax Recovery (m) 30 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.119	0.115	0.119
2	0.117	0.224	0.118
3	0.115	0.327	0.117
4	0.113	0.424	0.116
5	0.111	0.516	0.115
6	0.108	0.602	0.114
7	0.106	0.684	0.113
8	0.104	0.762	0.112
9	0.102	0.835	0.111
10	0.100	0.903	0.110
11	0.097	0.968	0.109
12	0.095	1.029	0.108
13	0.093	1.087	0.107
14	0.091	1.141	0.106
15	0.089	1.191	0.105
16	0.086	1.239	0.105
17	0.084	1.284	0.104
18	0.082	1.326	0.103
19	0.080	1.366	0.102
20	0.078	1.403	0.101
21	0.075	1.437	0.100
22	0.073	1.470	0.099
23	0.071	1.500	0.099
24	0.069	1.528	0.098
25	0.067	1.555	0.097
26	0.064	1.579	0.096
27	0.062	1.602	0.096
28	0.060	1.623	0.095
29	0.058	1.643	0.094
30	0.056	1.661	0.093

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_{HO}

Constant Dollars

($i = 3.77\%$)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
1	0.103	0.099	0.103
2	0.102	0.193	0.102
3	0.100	0.283	0.102
4	0.099	0.369	0.101
5	0.098	0.451	0.101
6	0.097	0.528	0.100
7	0.096	0.602	0.100
8	0.095	0.673	0.099
9	0.094	0.740	0.099
10	0.093	0.804	0.098
11	0.092	0.865	0.098
12	0.091	0.924	0.097
13	0.089	0.979	0.097
14	0.088	1.032	0.096
15	0.087	1.082	0.096
16	0.086	1.129	0.095
17	0.085	1.175	0.095
18	0.084	1.218	0.094
19	0.083	1.259	0.094
20	0.082	1.298	0.094
21	0.081	1.335	0.093
22	0.080	1.370	0.093
23	0.078	1.404	0.092
24	0.077	1.435	0.092
25	0.076	1.466	0.092
26	0.075	1.494	0.091
27	0.074	1.522	0.091
28	0.073	1.548	0.090
29	0.072	1.572	0.090
30	0.071	1.595	0.090

FOR ILLUSTRATIVE PURPOSES OF THIS GUIDE

Table VI_{HO}

Constant Dollars

($i = 3.77\%$)

Book Life (n) 60 Years
Tax Recovery (m) 60 Years
Without Tax Preferences

f Year	Year by Year Carrying Charge (CC_f)	Cumulative Present Value of Carrying Charge ($V_{f,m,n}$)	Levelized Carrying Charge ($P_{f,m,n}$)
31	0.070	1.618	0.089
32	0.069	1.639	0.089
33	0.067	1.658	0.089
34	0.066	1.677	0.088
35	0.065	1.695	0.088
36	0.064	1.712	0.088
37	0.063	1.728	0.087
38	0.062	1.743	0.087
39	0.061	1.758	0.087
40	0.060	1.771	0.086
41	0.059	1.784	0.086
42	0.058	1.796	0.086
43	0.056	1.808	0.086
44	0.055	1.819	0.085
45	0.054	1.829	0.085
46	0.053	1.839	0.085
47	0.052	1.848	0.085
48	0.051	1.856	0.084
49	0.050	1.865	0.084
50	0.049	1.872	0.084
51	0.048	1.879	0.084
52	0.047	1.886	0.083
53	0.045	1.893	0.083
54	0.044	1.899	0.083
55	0.043	1.904	0.083
56	0.042	1.910	0.082
57	0.041	1.915	0.082
58	0.040	1.919	0.082
59	0.039	1.924	0.082
60	0.038	1.928	0.082

```
10 !  Program ECONCC
20 !
30 PRINT CHR$(27);"h";CHR$(27);"J"    ! Home cursor, clear display
40 !
50 PRINT "Financial Analysis Program to Calculate Carrying Charges"
60 PRINT "EPRI P&E Version 2,  2/19/82"
70 PRINT
80 !  This program calculates present value and annuity factors; year-by-year,
90 !  cumulative present value, and levelized carrying charges; and other
100 ! parameters, based on input assumptions of book and tax life, costs of
110 ! financing, and tax rates.
120 !
130 ! Adapted for use by EPRI P&E staff, in Hewlett-Packard Terminal BASIC
140 ! on HP-2647 terminal, by Keith Brown.  Assumes slave printer setup;
150 ! slightly different logic needed for HP-IB printer.
160 !
170 DIM Temp(4,15),Depr(60)
180 Cl=0
190 PRINT "(Enter Rates as Decimals, Not Percents)"
200 PRINT
210 INPUT "Enter Costs of Debt, Pref., Equity:   ",Cd,Cp,Ce
220 PRINT
230 INPUT "Enter Debt Ratio, Pref. Ratios:       ",Dr,Pr
240 PRINT
250 INPUT "Enter Income Tax, ITC  Rates:         ",Tx,Itc
260 PRINT
270 IF Itc<=0 THEN 350
280 PRINT "Choose the Appropriate ACRS Class:"
290 PRINT "   1) Autos and light trucks - 3 yrs"
300 PRINT "   2) Office furniture and computers - 5 yrs"
310 PRINT "   3) Nuclear plant and combustion turbine - 10 yrs"
320 PRINT "   4) Fossil plant and T&D equipment - 15 yrs"
330 INPUT "Enter Class No.:             ",Cl
340 PRINT
350 INPUT "Enter Useful Book Life:     ",Bl
360 PRINT
370 INPUT "Enter today's date:         ",Date$
380 PRINT : PRINT
390 !
400 PRINT "Position paper to top of form, then press space bar ...  "
410 GETKBD ON                            !
420 IF GETKBD(X)=0 THEN 420            ! Set terminal to wait for signal
430 IF X<>32 THEN 420                  !
440 GETKBD OFF                           !
450 !
460 ! Calculate straight line tax depreciation
470 Sltxdp=1/Bl
480 ! Set tax life based on ACRS class
490 IF Cl=0 THEN 550
500 IF Cl=1 THEN Pl=3
510 IF Cl=2 THEN Pl=5
520 IF Cl=3 THEN Pl=10
530 IF Cl=4 THEN Pl=15
540 GOTO 570
550 ! Set tax life = book life when Itc = 0  (no tax preferences allowed)
560 Pl=Bl: GOTO 680
570 ! Store array for calculating accelerated depreciation
580 FOR I=1 TO 4
```

[redacted]

BEST DOCUMENT AVAILABLE

```
590 FOR J=1 TO 15
600 READ Temp(I,J)
610 NEXT J
620 NEXT I
630 DATA 33,45,22, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0, 0
640 DATA 20,32,24,16, 8, 0, 0, 0, 0, 0, 0, 0, 0, 0
650 DATA 10,18,16,14,12,10, 8, 6, 4, 2, 0, 0, 0, 0
660 DATA  7,12,12,11,10, 9, 8, 7, 6, 5, 4, 3, 3, 2, 1
670 ! Calculate depreciation for tax purposes
680 FOR I=1 TO 60:Depr(I)=0: NEXT I
690 FOR I=1 TO P1
700 IF Itc>0 THEN 730
710 ! Set tax depr = book depr when Itc = 0 & no tax preferences allowed
720 Depr(I)=Sltxdp: GOTO 750
730 IF I<B1 THEN Depr(I)=Temp(C1,I)/100
740 IF I>=B1 THEN Depr(B1)=Depr(B1)+Temp(C1,I)/100
750 NEXT I
760 ! Compute return rates used to determine carrying charges
770 Efi=(Cd*Dr+Cp*Pr+Ce*(1-Dr-Pr))*100  ! Total return (discount rate)
780 Er=1-Dr                             ! Equity ratio (includes pref.)
790 Ec=(Cp*Pr+Ce*(1-Dr-Pr))/Er          ! Equity cost  (includes pref.)
800 Pti=.02                             ! Property taxes and insurance
810 Bd=(1-Itc)/B1                       ! Book depreciation rate net of ITC
820 Sb=1-Itc                            ! Remaining amount on books
830 !
840 ! Title info
850 PRINT CHR$(27);"h";CHR$(27);"J"     ! Home cursor, clear display
860 PRINT : PRINT : PRINT
870 PRINT USING "25X25A,DD,6A";"Book Life (n)            ",B1," Years"
880 PRINT USING "25X25A,DD,6A";"Tax Recovery Period (m)  ",P1," Years"
890 PRINT USING "25X25A,DD.DDD,2A";"Discount Rate            ",Efi," %"
900 IF Itc>0 THEN PRINT TAB(32);"With Tax Preferences"
910 IF Itc<=0 THEN PRINT TAB(30);"Without Tax Preferences"
920 PRINT
930 PRINT USING "28X10A25X7A";"CumulativePresent"
940 PRINT USING 950;"Year by YearPresent Value ofLevelizedValueAnnuity"
950 IMAGE 9X12A4X16A5X9A9X5A3X7A
960 PRINT USING 970;"CarryingChargeCarryingChargeCarryingChargeFactorFactor"
970 IMAGE 8X8AX6A2X8AX6A3X8AX6A6X6A3X6A
980 PRINT USING 990;"f YearCCfVf,m,nPf,m,nv faf"
990 IMAGE 6A8X3A13X6A11X6A12X3A7X2A
1000 PRINT "------  ---------------  ---------------  ---------------";
1010 PRINT "     -------  -------"
1020 !
1030 ! Calculate carrying charges and other terms
1040 Cumdep,Pv,Sp,Pg=0
1050 FOR I=1 TO B1
1060 V=(1+Efi/100)I-I                   ! Present value factor
1070 A=(1-V)/(Efi/100)                  ! Annuity factor
1080 Td=Depr(I)                         ! Tax depreciation rate
1090 Cumdep=Cumdep+Td                   ! Cumulative tax depreciation
1100 Re=Sb*Er*Ec                        ! Return on common & pref.
1110 Rd=Sb*Dr*Cd                        ! Return on debt
1120 Dt=(Td-Sltxdp)*Tx                  ! Deferred income taxes
1130 Tp=Tx/(1-Tx)*(Bd-Td+Dt+Re)         ! Taxes paid
1140 Pv=Pv+Td*V                         ! Cum. present value of tax writeoff
1150 Cc=Bd+Dt+Rd+Re+Tp+Pti              ! Year-by-year carrying charge
1160 Sp=Sp+Cc*V                         ! Cum. pres. value of carrying chg.
```

[redacted]

```
1170 !
1180 PRINT USING 1190;I,Cc,Sp,Sp/A,V,A
1190 IMAGE 2X,DD,9X,.DDDD,13X,D.DDD,12X,.DDDD,11X,.DDDD,4X,DD.DDD
1200 IF I MOD 5=0 THEN PRINT      ! Print blank line after every 5th year entry
1210 !
1220 Sb=Sb-Bd-Dt                         ! Depreciate book value, net def. tax
1230 NEXT I
1240 !
1250 PRINT LIN(3);SPA(2);Date$;LIN(3)    ! Print date at bottom
1260 END
```

```
10 !  Program ECONLN
20 !
30 PRINT CHR$(27);"h";CHR$(27);"J"   ! Home cursor, clear display
40 !
50 PRINT "Financial Analysis Program to Calculate Levelizing Factors"
60 PRINT "EPRI P&E Version 1, 2/21/82"
70 !
80 !  This program computes levelizing factor 'Ln' based on input
90 !  assumptions of annual inflation rate 'Ei' & discount rate 'i' ('Com').
100 ! Annual real escalation rate 'Er' is varied in the program from 0-5%,
110 ! and Ln is printed out for three time periods: 10, 20, and 30 years.
120 !
130 ! Adapted for use by EPRI P&E staff, in Hewlett-Packard Terminal BASIC
140 ! on HP-2647 terminal, by Keith Brown.  Assumes slave printer setup;
150 ! slightly different logic needed for HP-IB printer.
160 !
170 DIM A(3),L(3)
180 PRINT "(Enter Rates as Decimals, Not Percents)"
190 PRINT
200 INPUT "Enter Annual Inflation Rate:     ",Ei
210 PRINT
220 INPUT "Enter Annual Discount Rate:      ",Com
230 PRINT
240 INPUT "Enter today's date:              ",Date$
250 PRINT
260 PRINT
270 PRINT "Position paper, then press space bar....  "
280 GETKBD ON                          !
290 IF GETKBD(X)=0 THEN 290           ! Set terminal to wait for signal
300 IF X<>32 THEN 290                 !
310 GETKBD OFF                         !
320 !
330 ! Title info
340 PRINT CHR$(27);"h";CHR$(27);"J"   ! Home cursor, clear display
350 PRINT LIN(7)
360 PRINT TAB(24),"Table II.  Levelizing Factor 'Ln'",LIN(1)
370 PRINT USING 390;"Inflation Rate (Ei)  ";Ei*100;"%"
380 PRINT USING 390;"Discount Rate  (i)   ";Com*100;"%"
390 IMAGE 25X22A,DD.DD,A
400 PRINT
410 PRINT USING "12X5A19X3A12X3A12X3A";"Er, %L10L20L30"
420 PRINT USING "12X5A18X5A10X5A10X5A";"--------------------"
430 !
440 FOR I=1  TO 18                   ! Loop on real escalation rate parameter
450 Er=2E-03*(I-1)                   ! Set real escalation rate
460 IF I=17 THEN Er=.04
470 IF I=18 THEN Er=.05
480 Ea=(1+Er)*(1+Ei)-1               ! Apparent escalation rate
490 K=(1+Ea)/(1+Com)                 ! Escalation factor
500 !
510 FOR J=1  TO 3                    ! Loop on year
520 Jj=J*10
530 A(J)=((1+Com)↑Jj-1)/(Com*(1+Com)↑Jj)     ! Annuity factor
540 L(J)=K*(1-K↑Jj)/(A(J)*(1-K))             ! Levelizing factor
550 NEXT J
560 !
570 PRINT USING 580;Er*100,L(1),L(2),L(3)
580 IMAGE 13X,D.D,19X,D.DDD,10X,D.DDD,10X,D.DDD
```

[redacted]

```
590 IF (Er*1000) MOD 10=0 THEN PRINT          ! Skip line every 5th entry
600 !
610 NEXT I
620 !
630 PRINT LIN(3);SPA(2);Date$;LIN(3)
640 END
```

Chapter B-4

UNCERTAINTY ANALYSIS

B-4.1 INTRODUCTION

Previous chapters described the method of economic comparison of alternatives to be used by EPRI and its contractors. This chapter extends the method to include the effects of uncertainty on each of the variables that affect the solution. A simple example will illustrate:

- How uncertainty affects decisions
- How to quantify expert opinion in the form of a subjective probability distribution
- How to bound and interpret the value of information collected to reduce uncertainty

B-4.2 EXAMPLE PROBLEM TO ILLUSTRATE UNCERTAINTY ANALYSIS

Consider competing technologies designated A and B. Assume that the decision to select these technologies is based on the book life levelized annual busbar cost.* In reality, if a technology had a lower levelized annual busbar cost but was constrained by the availability of resources for construction or operation, the technology with a higher levelized annual busbar cost might be chosen.

DETERMINISTIC ANALYSIS

Exhibit B-4-1 lists the variables that influence the levelized annual busbar cost and calculates this cost for each technology. Either Technology A with a levelized annual busbar cost of 48.18 mills/kWh or Technology B with a similar busbar cost of 49.02 mills/kWh can be chosen. Assuming the criteria of minimizing the levelized annual busbar cost, Technology A is preferred.

---

*The levelized annual busbar cost is only one possible value measure upon which generation expansion decisions may be based. The value measure chosen must result in a ranking of outcomes which is consistent with the preferences of the decision maker. A preceding chapter describes the different techniques used to calculate levelized annual busbar cost on a book life basis or on a first ten year basis.

[redacted]

SENSITIVITY ANALYSIS

The deterministic analysis assumed that each variable in Exhibit B-4-1 was known with certainty. However, most variables involved in the calculation are uncertain. The first step in incorporating uncertainty in the economic comparison is to perform a sensitivity analysis to determine if the reasonable range of uncertainty on each variable affects the decision. The sensitivity analysis is performed by setting all the variables at their nominal value and then, one by one, varying each at its upper and lower bound values and calculating the impact on levelized annual busbar cost. The variables that affect the decision are termed "sensitive". For these and only these variables it is necessary to treat their uncertainty quantitatively.

It is expensive and unnecessary to collect probabilistic information for all variables. The variables that do not affect decisions are kept at their nominal value during further analysis. Though there are no exact rules to determine the number of sensitivity runs, there are principles to bear in mind. Extreme values for each variable should be considered. If two or more variables are interdependent, they should be varied together.

Exhibit B-4-1

DETERMINISTIC DATA ASSUMPTIONS

Data Variable	*Technology A*	*Technology B*
Total capital requirements	$900/kW	$770/kW
Plant capacity factor	67%	67%
Fuel cost	$0.95/10^6 Btu	$0.95/10^6 Btu
Heat rate	10,000 Btu/kWh	11,000 Btu/kWh
Other fixed costs	$3.00 kW/yr	$5.00 kW/yr
Other variable costs	0.90 mills/kWh	2.17 mills/kWh
Date of commercial operation	1985	1985
Levelized annual busbar cost over 30-year book life	48.18* mills/kWh	49.02 mills/kWh

*See below for sample calculation of 30 Year Levelized Annual Busbar Cost for Technology A.

[redacted]

$$\text{LBB}_A = \frac{(\$900/\text{kW})\ (30\text{-yr LRR rate})\ (1000\text{ mills/dollar})}{(1.0\text{ kW})\ (8760)\ (0.67)\text{ hours}}$$

$$+ \left(\frac{\$0.95}{10^6\text{ Btu}}\right)\left(\frac{1000\text{ Btu}}{\text{kWh}}\right)(L_{30})\ (1000\text{ mills/dollars})$$

$$+ \frac{(\$3.00/\text{yr})\ (L_{30})\ (1000\text{ mills/dollars})}{(1.0\text{ kW}\ (8760)\ (0.67)\text{ hours}}$$

$$+ (0.90\text{ mills/kWh})\ (L_{30})$$

$$= 48.18\text{ mills/kWh}$$

where L_{30} = 1.886 is from Table II appended to Chapter B-3 and
the 30-yr levelized carrying change rate is assumed to be 0.180.

Exhibit B-4-2 is an abbreviated table of results from the sensitivity analysis. All variables not appearing are assumed to be insensitive. The exhibit shows that Technology B is recommended for some values of the Technology A capital cost. In contrast, though changes in fuel price affect the levelized busbar cost, they do not change the technology recommended. Similarly, the choice of technology is not affected by the capital cost of Technology B. Thus in this example, capital cost of Technology A is a sensitive variable, and fuel price and capital cost of Technology B are not.

SUBJECTIVE UNCERTAINTY

Having determined that a variable is sensitive and could affect the decision, a technique to deal with the uncertainty must be used. Further research may be undertaken to reduce the uncertainty, but it is unlikely that all uncertainty can be removed. When a decision is required, the decision maker must rely on expert judgement or opinion. One way to quantify the opinion of an expert is to obtain that person's subjective probability distribution.

A probability distribution represents the relative likelihood of specific outcomes for an uncertain variable. The distribution quantitatively describes the state of information on the variable. In some cases, the information may be based on actual experience (e.g., the unplanned outage rate for an existing type of generating unit). The results of a frequently repeated experiment define an objective proability distribution. In other cases, little objective information may be available (e.g., the capital costs of a technology not yet commercialized), and the information base may consist primarily of judgement and opinion. In this case, uncertainty is quantified as subjective probability distribution.

Data Variable	Variable Setting		Levelized Annual Busbar Cost (mills/kWh)	
			Technology A	*Technology B*
Capital cost:	Low	800	➤ 45.11	49.02
Technology A	Nominal	900	➤ 48.18	49.02
($/kW)	High	1150	55.85	➤ 49.02
Fuel cost:	Low	0.91	➤ 47.43	48.19
Technology A	Nominal	0.95	➤ 48.18	49.02
($/10^6 Btu)	High	1.16	➤ 52.14	53.38
Capital cost:	Low	750	➤ 48.18	48.41
Technology B	Nominal	770	➤ 48.18	49.02
($/kW)	High	830	➤ 48.18	50.86

Other variables assumed not sensitive, ➤ indicates preferred decision.

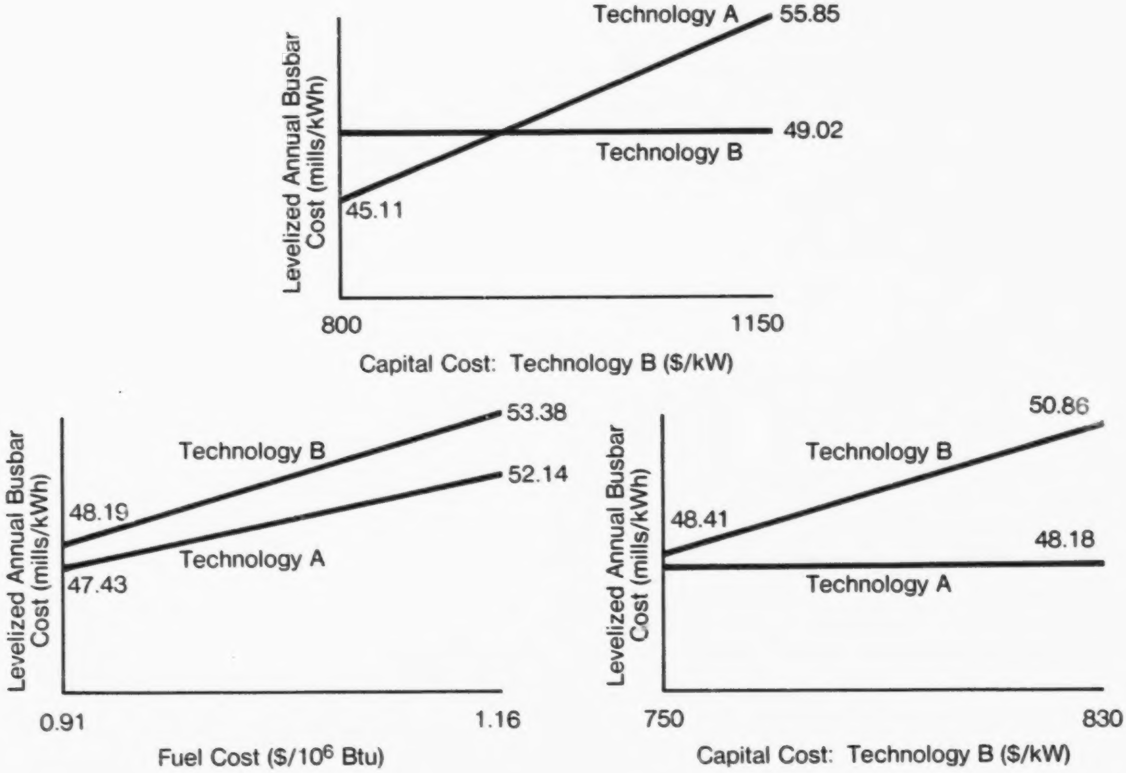


Exhibit B-4-2. Abreviated sensitivity analysis.

The subjective probability distribution on each sensitive variable is encoded during an interview. Questions are asked regarding the likelihood of each value of the variable. The responses represent the subjective beliefs about the relative likelihood of each possible value of the variable. It is based on the state of information of the interviewee, who is either the decision maker or a delegated representative.

A key task facing the interviewer is to identify and minimize any biases in the responses obtained. Conscious or subconscious discrepancies between the interviewee's responses and an accurate description of his underlying knowledge are termed biases. A displacement bias shifts the whole distribution in one direction. A change in the shape of distribution is called a variability bias. Frequently, a central bias causes the distribution to be tighter than is justified. Biases can be caused by giving too much weight to recent experiences or by fixing on a central estimate. References 15 to 20 describe the encoding process and the procedures for dealing in detail with biases.

Exhibit B-4-3 illustrates a sample subjective probability distribution on the capital cost of Technology A. The upper part of the diagram shows the probability density function for this variable. It displays the interviewee's beliefs on the likelihood that the capital cost of Technology A will be a specific value. It is usually most convenient to elicit information as a cumulative probability distribution since the interviewee can respond more easily to questions regarding the likelihood of a variable being less (or greater) than, rather than equal to, a particular value.

In Exhibit B-4-3, a staircase is superimposed on the continuous distribution. If the triangles above and below the continuous distribution are drawn to have equal areas, the discrete values will adequately approximate the uncertainty. The accuracy of this approximation increases with the number of steps used. The insert in Exhibit B-4-3 shows the discrete representation of the distribution. The choice of intervals shown (0.25, 0.5, 0.25) coincide with discrete representations of data which appear in Appendix C of the white pages.

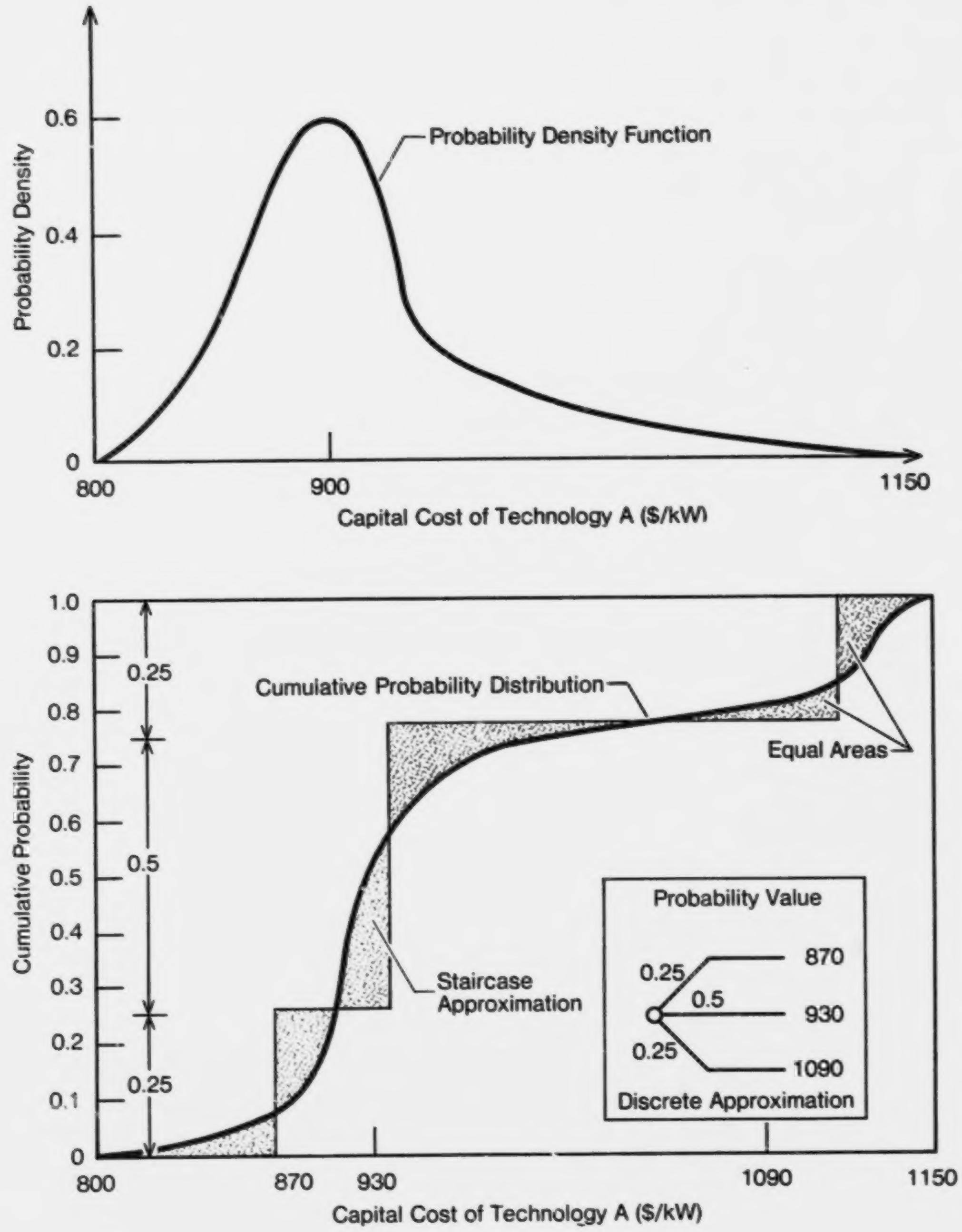


Exhibit B-4-3. Subjective probability distribution.

[redacted]

PROBABILISTIC ANALYSIS

After assigning probability distributions to the sensitive variables, it is straightforward to determine the probability of busbar costs for each alternative. Through this process the consideration of uncertainty is incorporated in determining the recommended decision.

Exhibit B-4-4 shows a decision tree that represents the structure of all possible sequences of decisions and outcomes and provides for cost, value, and probability inputs. Emanating from the decision node (marked by the X) are branches symbolizing the two possible alternatives. The arrow on the lower branch indicates the preferred decision. Emanating from each chance node (marked by the O) is a set of outcomes representing the discrete approximation for each sensitive variable. To each outcome a probability and value is assigned. By multiplying the value of each outcome by its corresponding probability and summing, an expected value is calculated.* As shown in Exhibit B-4-4, the expected levelized annual busbar cost for alternatives A and B are 49.87 and 49.02 mills/kWh, respectively. Note that when considering uncertainty, the preferred decision has been reversed, and Technology B is now recommended.

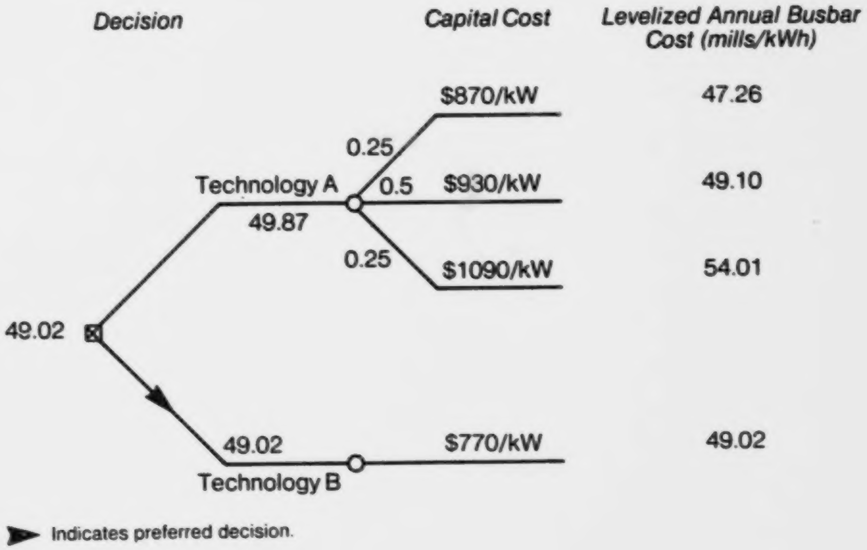

Decision
Capital Cost
Levelized Annual Busbar Cost (mills/kWh)
$870/kW
47.26
0.25
Technology A
0.5
$930/kW
49.10
49.87
0.25
$1090/kW
54.01
49.02
49.02
$770/kW
49.02
Technology B
Indicates preferred decision.

Exhibit B-4-4. Probabilistic decision tree.

---

*Note: It is assumed that the decision maker bases decisions on expected values or that he is risk neutral.

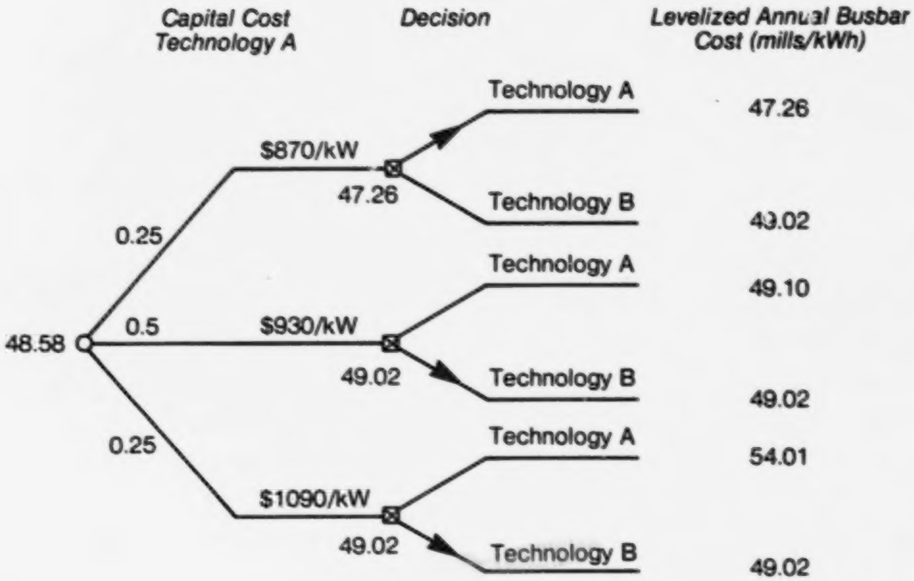
VALUE OF PERFECT INFORMATION

The subjective probability distribution reflects the state of knowledge of the decision maker. Additional information can change the state of knowledge and thus can modify the subjective probabilities attached to various outcomes. This reduction in uncertainty may change the decision and could result in a better outcome. However, collecting additional information is costly. To determine the advisability of collecting better information on a particular variable, a value of information calculation can be made. This section shows how the value of perfect information (information which removes all uncertainty) is determined.

The value of perfect information is an upper bound on the value of resources that can be devoted to collecting better information on a variable. The value of information on a particular variable depends on the uncertainty the decision maker has about its true value. Exhibit B-4-5 shows the calculation of the value of perfect information on the capital cost of Technology A. As shown, this is done by reversing the order of the decision and chance nodes in the decision. This indicates that if perfect information were available, the decision could be made after the actual value of the uncertain variable was revealed.

When we inquire as to what the capital cost of Technology A will be, we know that there is a 0.25 chance the answer will be \$870/kW, 0.5 it will be \$930/kW and a 0.25 chance of being \$1090/kW. Since the decision is made after the value of capital cost of Technology A is known, we can obtain a better outcome (i.e., a lower levelized busbar cost) when capital cost is \$870/kW by reversing our decision an choosing Technology A.

The assumption of an expected value decision maker simplifies the calculation of the value of information. Without perfect information, the expected busbar cost is 49.02 mills/kWh and Technology B is chosen. If perfect information is obtained, the decision can be improved. If the cost is \$870/kW, Technology A will be chosen. If the value is either \$930/kW or \$1090/kW, Technology B is chosen. The expected busbar cost is 48.58 mills/kWh. The difference between the expected cost with and without the information is the value of perfect information. In this case, it is 0.44 mills/kWh. Assuming a plant size of 1000 MW and a capacity factor of 0.67, this is equivalent to an expected annual value of approximately 26 million dollars per plant. This figure represents the maximum value of obtaining better information on capital costs of Technology A. While it is unlikely that research will result in perfect information, the relative magnitude


Capital Cost Technology A
Decision
Levelized Annual Busbar Cost (mills/kWh)
48.58
0.25
0.5
0.25
$870/kW
47.26
$930/kW
49.02
$1090/kW
49.02
Technology A
Technology B
Technology A
Technology B
Technology A
Technology B
47.26
49.02
49.10
49.02
54.01
49.02

Value of perfect information = 49.02 − 48.58 = 0.44 mills/kWh

► Indicates preferred decision.

Exhibit B-4-5. Value of perfect information.

of the value of information on different uncertain variables provides guidance as to where further research activities should be directed.

A value of information calculation can be used by EPRI in selecting research and evaluating development and demonstration projects. While the number of variables which must be considered in the R&D process is much more extensive, the value of projects designed to improve the information base on which utilities make decisions can be quantified using the framework described in this chapter. An expanded analysis should include constraints on siting, fuel, manpower and capital availability, environmental and social requirements, and project interdependencies.

B-4.3 SUMMARY

This chapter has provided one method for incorporating uncertainty into the economic analysis of competing technologies. The method includes deterministic modeling, sensitivity analysis, encoding subjective probabilities, probabilistic modeling, and calculation of the value of information. It was shown by a simple example how the consideration of uncertainty can change recommended decisions. It is hoped that adoption of this method can lead to greater use of quantitative analysis in the decision making process.

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Chapter B-5

SAMPLE CALCULATIONS

This chapter is a collection of sample calculations to illustrate the economic methodology that has been presented earlier. Its purpose is to serve as a general guide for handling the several types of economic situations that one may encounter at EPRI.

In all cases, economic factors for these sample problems are taken either from the tables appended to Chapter B-3 of the yellow pages or are calculated for a special situation using the economic parameters shown on the first page of the tables appended to Chapter B-3. The computer program listing is given at the end of the tables. Current economic factors for actual problems are found in Appendix A of the white pages.

For each of the sample problems in this chapter, there is a list of Keywords. These will help identify the ramifications of each problem so that the reader can make greater use of this Guide.

[redacted]

SAMPLE CALCULATION I

TITLE

Break-even cost of municipal refuse-derived fuels (RDF)

KEYWORDS

Sunk cost
Break-even fuel cost
Less than 30-year life for new equipment
Incremental fuel cost
Incremental operating and maintenance cost
Current-dollar analysis

STATEMENT OF PROBLEM

An electric utility is evaluating a proposal from a municipality to burn RDF as a supplemental fuel in a coal-fired utility boiler. The utility's rate-regulating body has agreed to allow this provided that the cost of producing electric energy does not change. Using current-dollars, determine the price that the utility could pay for RDF.

DISCUSSION

Based on the material presented above, the revenue requirement of the candidate technology must be equal to the incremental cost (revenue requirement) of producing electric energy using existing methods and equipment. In actual practice, the present cost is usually taken as the system average incremental cost of energy as obtained from a production cost study. The average incremental cost would be the average cost of the next increment of energy for the period of time that RDF would be consumed. In order to simplify the solution of this sample problem, the average incremental cost of energy will be considered to be the cost of producing energy from an existing 500-MW coal-fired power plant operating at a 30% capacity factor.

When RDF is used, it would be consumed in a fuel mixture that is 80% coal and 20% RDF in the same 500-MW unit, modified as necessary to accommodate the coal-RDF mixture. Assume in this example that there is no change in unit availability or forced outage rate.

Data(1, 4)	*Alternative A*(2) *Normal Operation Using Coal*	*Alternative B*(3) *Operation Using Coal-RDF Mixture*
Energy supplied	(500,000 kW) (8760 h/yr) (0.3 yr) $= 1.314 \times 10^9$ kWh	Same
Heat rate(4)	10,149 Btu/kWh	10,455 Btu/kWh
Fuel cost — coal — RDF	$1.55/million Btu(5)	$1.55/million Btu(5) To be determined
Incremental O&M(7)	4.0 mills/kWh(5)	6.0 mills/kWh(5)
Additional investment to burn RDF	—	$78,500,000(6)
Service date of RDF	—	Year Z+5
Equipment life	20 years remaining of existing 500 MW plant	Equal to 20 years, the remaining life of the existing equipment

(1) It must be emphasized that the quantities given here are representative values for illustrative purposes only. Economic factors are taken from the tables appended to Chapter B-3 of the yellow pages. In a real situation, if specific information is available, that material must be used along with appropriate economic factors from Appendix A of the white pages. All cost estimates are given in December, year Z−1 dollars.

(2) Data for the existing 500 MW unit is similar to a unit described in Appendix B of the white pages. A reasonable facsimile of the appropriate Appendix B sheet is included as page B-5-I-9 since the real Appendix B sheet will be revised from time to time as conditions change.

(3) This estimate is based on technical information derived in the hypothetical project.

(4) The value stated here is the average heat rate for operation at a 70% load level.

(5) Subject, as appropriate, to a real escalation rate (e_r) of 0.8% per year and an inflation rate (e_i) of 6.0% per year.

(6) Total capital requirement for a year Z inservice date that is subject to an inflation rate (e_i) of 6% per year from the reference year until the plant goes into service (capitalized).

(7) It is assumed that the fixed O&M would be the same for either alternative and therefore is not included.

SOLUTION

To determine the break-even price of RDF, the revenue requirements for the two alternatives are set equal. This can be done over the book life, over a shorter period such as 10 years, or on a year-by-year basis (see Chapter B-3). For this sample problem, a year-by-year analysis and a first-10-year analysis will be made.

[redacted]

Since the remaining life of the existing 500-MW plant is 20 years, Table III based on a 30-year physical (book) life and 15-year tax recovery period cannot be used for the new equipment (20-year physical life equal to the existing 500-MW plant) without introducing an error into the calculation. However, using the computer program ECONCC listed at the end of the tables of Chapter B-3, appropriate carrying charge factors can be computed for the new investment.

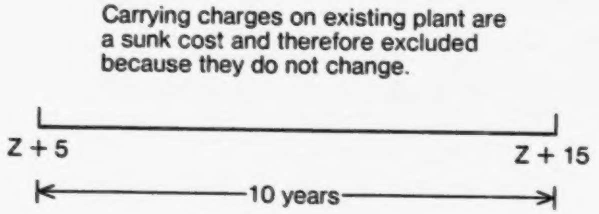
A special computer run for these special conditions is presented below

```
                                Book Life (n)             20 Years
                                Tax Recovery Period (m)   15 Years
                                Discount Rate             10.000 %
                                     With Tax Preferences

                                  Cumulative                              Present
               Year by Year    Present Value of     Levelized              Value    Annuity
              Carrying Charge  Carrying Charge    Carrying Charge         Factor    Factor
 f Year            CCf           Vf,m,n             Pf,m,n                 v f        af
 ------    ---------------   ----------------   ---------------         -------   -------
    1           0.204            0.185              0.204                .9091     0.909
    2           0.195            0.347              0.200                .8264     1.736
    3           0.182            0.484              0.195                .7513     2.487
    4           0.170            0.600              0.189                .6830     3.170
    5           0.158            0.698              0.184                .6209     3.791

    6           0.146            0.780              0.179                .5645     4.355
    7           0.136            0.850              0.175                .5132     4.868
    8           0.126            0.909              0.170                .4665     5.335
    9           0.118            0.959              0.166                .4241     5.759
   10           0.110            1.001              0.163                .3855     6.145

   11           0.102            1.037              0.160                .3505     6.495
   12           0.096            1.068              0.157                .3186     6.814
   13           0.090            1.094              0.154                .2897     7.103
   14           0.085            1.116              0.151                .2633     7.367
   15           0.080            1.135              0.149                .2394     7.606

   16           0.076            1.152              0.147                .2176     7.824
   17           0.073            1.166              0.145                .1978     8.022
   18           0.070            1.179              0.144                .1799     8.201
   19           0.066            1.190              0.142                .1635     8.365
   20           0.063            1.199              0.141                .1486     8.514
```

[redacted]

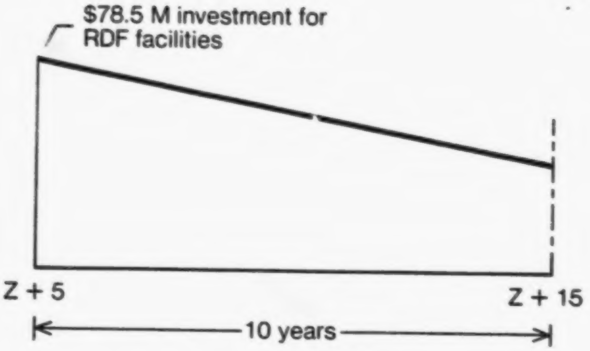
The time diagrams are presented below

Alternative A


Carrying charges on existing plant are a sunk cost and therefore excluded because they do not change.

Fuel cost = \$1.55/MBtu
O&M = 4.0 mills/kWh
Energy = 1.314×10^9 kWh

Alternative B


$78.5 M investment for RDF facilities

Coal fuel cost = \$1.55/MBtu
RDF fuel cost = To be determined
O&M = 6.0 mills/kWh
Energy = 1.314×10^9 kWh

Note: All cost estimates are in December, year Z−1 dollars.

Alternative A Revenue Requirement[1]

Fuel Cost Expense	Line 1
O&M Expense	Line 2
Carrying Charge on existing plant is a sunk cost and is not included (see Section B-2.3)	---

---

[1] See calculations below.

Alternative B Revenue Requirement[1]

Carrying Charge on additional investment	Line 3
Coal Fuel Cost Expense	Line 4
RDF Fuel Cost Expense	Line 5
O&M Expense	Line 6

---

[1] See calculations below.

The first task is to bring all of the cost estimates from beginning of year Z dollars to dollars at the beginning of year Z+5 when the proposed RDF program would begin operation. (See Section B-1.3) Then a year-by-year analysis and a first-10-year analysis will be made.

Line 1

The apparent escalation rate is based on $e_r = 0.008$ and $e_i = 0.06$.

$$\begin{aligned} 1+e_a &= [(1+0.008)\,(1+0.06)] \\ &= 1.0685 \end{aligned}$$

thus,

$$\begin{aligned} \text{Cost of coal} &= \$1.55\,(1.0685)^5 \\ &= \$2.16/\text{million Btu} \end{aligned}$$

and

$$\begin{aligned} \begin{array}{r}\text{Annual cost}\\ \text{of coal}\\ \text{in year } Z+5\end{array} &= (\$2.16\times10^{-6}/\text{Btu})\,(10149\ \text{Btu/kWh})\,(1.314\times10^{9}\ \text{kWh}) \\ &= \underline{\underline{\$28{,}800{,}000}} \end{aligned}$$

Line 2

The apparent escalation rate is based on $e_r = 0$ and $e_i = 0.06$.

$$1+e_a = 1+0.06$$

[redacted]

thus,

$$\begin{aligned} \text{O\&M} &= (4.0 \text{ mills/kWh})\,(1.06)^5 \\ &= 5.35 \text{ mills/kWh} \end{aligned}$$

and

$$\begin{aligned} \begin{matrix}\text{Annual O\&M}\\ \text{in year Z+5}\end{matrix} &= (5.35 \text{ mills/kWh})\,(1.314\times10^9 \text{ kWh}) \\ &= \underline{\underline{\$7{,}030{,}000}} \end{aligned}$$

Line 3

The apparent escalation rate is based on $e_r = 0$ and $e_i = 0.06$

$$\begin{aligned} (1+e_a)^5 &= (1+0.06)^5 \\ &= 1.338 \end{aligned}$$

and

$$\begin{aligned} \begin{matrix}\text{Investment}\\ \text{in year Z+5}\end{matrix} &= (\$78{,}500{,}000)\,(1.338) \\ &= \underline{\underline{\$105{,}000{,}000}} \end{aligned}$$

Line 4

The apparent escalation rate is the same as Line 1, so that the cost of coal is \$2.16/million Btu. In Alternative B, 80% of the fuel mixture is coal.

$$\begin{aligned} \begin{matrix}\text{Annual cost}\\ \text{of coal}\\ \text{in year Z+5}\end{matrix} &= (\$2.16\times10^{-6}/\text{Btu})\,(10455 \text{ Btu/kWh})\,(1.314\times10^9 \text{ kWh})\,(0.8) \\ &= \$23{,}700{,}000 \end{aligned}$$

Line 5

This is the unknown quantity and is equal to

$$\text{Line 1} + \text{Line 2} - \text{Line 3} - \text{Line 4} - \text{Line 6 in dollars in year f}$$

$$\begin{aligned} \text{Line 5 in \$/million Btu} &= \frac{\text{year f dollars} \times 10^6}{(10455)\,(1.314 \times 10^9)\,(0.2)} \\ &= \frac{\text{year f dollars}}{2.748 \times 10^6} \end{aligned}$$

Line 6

The apparent escalation rate is the same as Line 2

$$\text{O\&M} = (6.0\text{ mills/kWh})\,(1.338)$$
$$= 8.03\text{ mills/kWh}$$

$$\begin{array}{r}\text{Annual O\&M}\\ \text{in year Z+5}\end{array} = (8.03\text{ mills/kWh})\,(1.314\times10^{9}\text{ kWh})$$
$$= \underline{\underline{\$10{,}600{,}000}}$$

The year-by-year analysis (see Section B-3-12) will be completed for each of the first 10 years. All costs are in millions of dollars except the right-hand column which is in actual $/MBtu.

	Alternative A		*Alternative B*				
Year t	*Fuel Cost (Line 1)* $28.8\,(1.0685)^t$	*O&M (Line 2)* $703\,(1.06)^t$	*CC (Line 3)* $105\,CC_t$	*Coal Cost (Line 4)* $23.7\,(1.0685)^t$	*O&M (Line 6)* $10.6\,(1.06)^t$	*RDF Cost (3)*	*$/MBtu(4)*
1	30.77(1)	7.45(1)	21.42(2)	25.32(1)	11.23(1)	−19.75	−7.19
2	32.88	7.90	20.48	27.06	11.91	−18.67	−6.79
3	35.13	8.37	19.11	28.91	12.62	−17.14	−6.24
4	37.54	8.88	17.85	30.89	13.38	−15.70	−5.71
5	40.11	9.41	16.59	33.01	14.19	−14.27	−5.19
6	42.86	9.97	15.33	35.27	15.04	−12.81	−4.66
7	45.79	10.57	14.28	37.68	15.94	−11.54	−4.20
8	48.93	11.20	13.23	40.27	16.89	−10.26	−3.73
9	52.28	11.88	12.39	43.02	17.91	−9.16	−3.33
10	55.86	12.59	11.55	45.97	18.98	−8.05	−2.93

(1) Since investments are placed in service at the beginning of the year, but all carrying charges and expenses are paid at the end of the year, it will be necessary to inflate all expense amounts in full year increments (see Section B-2-9).

(2) Carrying charge factors for this sample problem were obtained from a special computer run of ECONCC (see page B-5-I-3) using the economic parameters for the tables appended to Chapter B-3 of the yellow pages. Use similar data from Appendix A of the white pages, together with ECONCC, for real problems of this nature.

(3) Equal to Line 1+Line 2−Line 3−Line 4−Line 6.

(4) Actual $/MBtu.

The utility payments for RDF shown in the two right-hand columns are negative and therefore indicate that the municipality would have to pay the utility each year in order that the utility would be made whole in the RDF operation. The fee varies from $7.19 per million Btu in year 1 to $2.93 per million Btu in year 10.

[redacted] BEST DOCUMENT AVAILABLE

Another type of analysis is the first 10-year levelized short-term analysis (see Section B-3.13). In the following, all costs are given in millions of year Z+5 dollars except for the final cost, which is in dollars per million Btu in year Z+5 dollars.

$$\begin{aligned}\text{1st 10 year LRR}_A &= \$28.80L_{10} + \$7.03L_{10}\\ &= 28.80\,(1.392) + 7.03\,(1.335)\\ &= \$49.47\end{aligned}$$

Note that the first levelizing factor (for the fuel cost) is based on a 0.8% real escalation rate and a 6.0% inflation rate. The second levelizing factor (for the O&M cost) is based only on a 6.0% inflation rate. (Use Table II appended to Chapter B-3 of the yellow pages).

$$\begin{aligned}\text{1st 10 year LRR}_B &= \$105\,P_{10,15,20} + \$23.7L_{10} + X + \$10.6L_{10}\\ &= 105\,(0.163) + 23.7\,(1.392) + X + 10.6\,(1.335)\\ &= 17.12 + 32.99 + X + 14.15\\ &= 64.26 + X\end{aligned}$$

Again, note that the levelizing factors L_{10}, taken from Table II depend upon the real escalation rate as well as the inflation rate. The factor $P_{10,15,20}$ is taken from the special run of ECONCC (see page B-5-I-3).)

$$\begin{aligned}LRR_A &= LRR_B\\ 49.47 &= 64.26 + X\\ x &= -14.79\\ &= -\$5.38/\text{million Btu}\end{aligned}$$

In either case, the cost per million Btu could be converted to cost per ton so that the municipality could compare RDF to other disposal alternatives such as land fill.

SAMPLE GENERATING TECHNOLOGIES DATA SHEET

Generation Type: Coal-Steam with Wet Limestone FGD
Geographic Region: East Central

Unit Size, Net Electrical Output, MW (e)		500
Available for Commercial Orders, Year		Current
First Commercial Service, Year		Current
Unit Capital Costs, $/kW, based on Plant Size of (No. Units x Unit Size)		2 x 500
Total Plant Cost (December, year Z-1 $)		803
Total Plant Investment[a]		834
Start up, Inventory, Land (December, year Z-1 $)		43
Total Capital Requirement (December, year Z-1 $)		877
Operating and Maintenance Costs (December, Year Z-1 $)		
Fixed	($kW-yr)	13.9
Incremental		
Variable	(mills/kWh)	1.0
Consumables	(mills/kWh)	3.0
Heat Rate, Btu,kWh		
Full Load		9853
75% Load		9952
50% Load		10448
Average Annual for 70% Load Operation		10149
Type of Operation (nominal)		Base/Int.
Minimum Load, % of Full Load		25
Preconstruction and Licensing Lead Time, Years		2
Design/Construction Time, Years		5
Unit Life, Years		30
Technology Development Rating		5
Design, Cost Estimate Rating		3

---

[a] Includes AFDC and Escalation for a January 1, year Z, Service.

[redacted]

SAMPLE CALCULATION II

TITLE

Break-even cost of replacement stacks for fuel cells.

KEYWORDS

Break-even cost
Interim replacements of components at less than book life
Book life less than tax recovery period
Inflation
Book life analysis
Short-term analysis
Current-dollar analysis

STATEMENT OF PROBLEM

In connection with the development of a molten carbonate fuel cell (gasification-combined-cycle), a portion of the device called the stack is expected to have a useful life of 5 years or only 1/6 of the 30-year book life of the overall unit. Using current dollars, determine the break-even cost of a replacement stack if the useful life could be increased to 10 years.

DISCUSSION

The revenue requirement of the 5-year stack, with replacements, must be equal to the revenue requirement of the 10-year stack, with replacements. A relatively simple analysis can be made if it can be assumed that all other costs and overall reliability would be equal in either case and that (1) the downtime for stack replacement is negligible or (2) stack replacement would not be a critical-path item when the fuel cell is down for other reasons.

[redacted]

Data(1, 3)	*Alternative A Present Design*(2)	*Alternative B Proposed Alternate*
Cost of stack	$55/kW	To be determined
Life	5 years	10 years
Service date	Year Z+3	Year Z+3

(1) It must be emphasized that the quantities given here are representative values for illustrative purposes only. Where possible, economic factors are taken from the tables appended to Chapter B-3 of the yellow pages. In a real situation, if more specific information is available, that material must be used along with appropriate economic factors from Appendix A of the white pages.

(2) Data for the present design fuel cell units are similar to those of a unit described in Appendix B of the white pages. A reasonable facsimile of the appropriate Appendix B sheet is included as page B-5-II-7 since the real Appendix B sheet will be revised from time to time as conditions change. The $55/kW stack cost is subject to a 6% inflation rate.

(3) All cost estimates are given in December, year Z−1 dollars.

SOLUTION

To determine the break-even cost of the longer-lived stack, the revenue requirement for the two alternatives are set equal. This should be done over the book life of the fuel cell (see Chapter B-3), since neither a shorter period (such as 10 years) nor a year-by-year analysis would be appropriate for this situation.

Since it has been assumed that the only difference between the two alternatives involves the life and price of the stack, all other carrying charges and expenses are equal and can be excluded.

When making economic studies for EPRI, occasionally one will encounter interim replacements of components at less than the book life of the major investment item. Using the program ECONCC (listing appended to Chapter B-3), carrying charges are easily obtained. If the book life is less than the tax recovery period, at the end of the book life the program automatically deducts the remaining unrecovered investment for tax purposes. ECONCC runs for n = 5, m = 15, and n = 10, m = 15 are presented below.

[redacted]

Book Life (n) 5 Years
Tax Recovery Period (m) 15 Years
Discount Rate 10.000 %
With Tax Preferences

f Year	Year by Year Carrying Charge CCf	Cumulative Present Value of Carrying Charge Vf,m,n	Levelized Carrying Charge Pf,m,n	Present Value Factor v f	Annuity Factor af
1	0.324	0.295	0.324	.9091	0.909
2	0.306	0.547	0.315	.8264	1.736
3	0.283	0.760	0.306	.7513	2.487
4	0.261	0.938	0.296	.6830	3.170
5	0.239	1.087	0.287	.6209	3.791

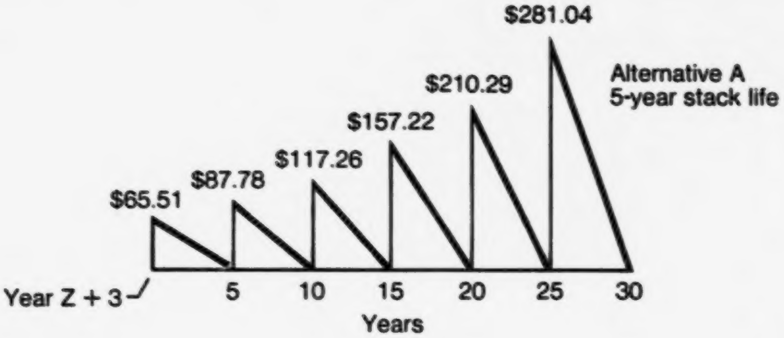
Book Life (n) 10 Years
Tax Recovery Period (m) 15 Years
Discount Rate 10.000 %
With Tax Preferences

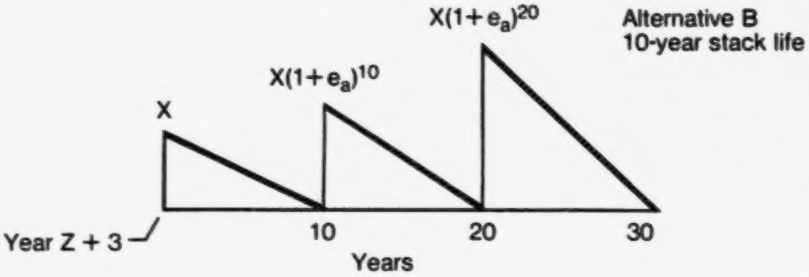
f Year	Year by Year Carrying Charge CCf	Cumulative Present Value of Carrying Charge Vf,m,n	Levelized Carrying Charge Pf,m,n	Present Value Factor v f	Annuity Factor af
1	0.244	0.222	0.244	.9091	0.909
2	0.232	0.414	0.238	.8264	1.736
3	0.216	0.576	0.232	.7513	2.487
4	0.200	0.712	0.225	.6830	3.170
5	0.185	0.827	0.218	.6209	3.791
6	0.170	0.923	0.212	.5645	4.355
7	0.157	1.004	0.206	.5132	4.868
8	0.144	1.071	0.201	.4665	5.335
9	0.132	1.127	0.196	.4241	5.759
10	0.121	1.174	0.191	.3855	6.145

The cost estimate is provided on a per-kW basis for a 1000-MW plant. The analysis will be performed on a per-kW basis to eliminate the need to carry zeros.

[redacted]

The time diagrams are presented below:


$281.04
$210.29
$157.22
$117.26
$87.78
$65.51
Alternative A
5-year stack life
Year Z + 3
5
10
15
20
25
30
Years


X(1+e_a)^20
Alternative B
10-year stack life
X(1+e_a)^10
X
Year Z + 3
10
20
30
Years

Alternative A Revenue Requirements[1]

Carrying charges on original stack	Line 1
Cost of replacement stacks	Line 2

Alternative B Revenue Requirements[1]

Carrying charges on original stack	Line 3
Cost of replacement stacks	Line 4

---

[1] See calculations below.

The first task is to bring all of the cost estimates from beginning of year Z dollars to dollars at the beginning of year Z+3, the service date of the fuel cell (see Section B-1.3).

Line 1

The apparent escalation rate is based on

$$e_r = 0 \quad e_i = 0.06$$

$$\begin{aligned} 1+e_a &= [(1+e_r)\,(1+e_i)] \\ &= (1+0.06) \end{aligned}$$

Thus,

$$\begin{aligned} \text{Cost of initial stack in year } Z+3 &= (\$55.00)\,(1.06)^3 \\ &= \underline{\underline{\$65.51}} \end{aligned}$$

Present value of carrying charges equals \$65.51 times the factor $V_{15,5}$ obtained from a special computer run of ECONCC.

$$V_{15,5} = 1.087$$

Line 2

The apparent escalation rate is the same as Line 1.

Year of Replacement[1] n	Escalation Factor $(1.06)^n$	Cost of Replacement Stack
5	1.34	\$ 87.78
10	1.79	117.26
15	2.40	157.22
20	3.21	210.29
25	4.29	281.04

---

[1] Years after year Z+3.

Lines 3 and 4

The apparent escalation rate is the same as Line 1, and the break-even costs will be determined using algebra. The appropriate escalation factors can be taken from the Line 2 table (above).

The book life analysis (see Section B-3.7) is performed over the entire 30-year book life. Because of the nature of the problem, it will be better to make a present value analysis as opposed to a levelized analysis.

Appropriate factors for the break-even calculation are from Table I and from the special computer run made with ECONCC.

$$
\begin{aligned}
\mathrm{PVRR}_A &= \$65.51V_{15,5} + \$87.78V_{15,5}v^{5} + \$117.26V_{15,5}v^{10} + \$157.22V_{15,5}v^{15} \\
&\quad + \$210.29V_{15,5}v^{20} + \$281.04V_{15,5}v^{25} \\
&= (1.087)\,[65.51 + 87.78\,(0.621) + 117.26\,(0.386) \\
&\quad + 157.22\,(0.239) + 210.29\,(0.149) + 281.04\,(0.092)] \\
&= \$282.67 \\
\mathrm{PVRR}_B &= XV_{15,10} + XV_{15,10}(1.06)^{10}v^{10} + XV_{15,10}(1.06)^{20}v^{20} \\
&= X(1.174)\,[1.000 + (1.79)\,(0.386) + (3.21)\,(0.149)] \\
&= X(2.547)
\end{aligned}
$$

Setting PVRR_A to PVRR_B and solving

$$
\begin{aligned}
X &= \frac{282.67}{2.547} \\
&= \$110.98
\end{aligned}
$$

This value is in year Z+3 dollars.Thus, a fuel cell stack that lasts 10 years and costs \$110.98 is equal, economically, to a 5-year stack costing \$65.51.

SAMPLE GENERATION COSTS AND CHARACTERISTICS

Generation Type: Fuel Cell Combined Cycle-Texas Gasifier
Region: East Central

Unit Size, Net Electrical Output, MW		1000
Available for Commercial Orders, Year		1990
First Commercial Service, Year		1995
Unit Capital Costs, $/kW, based on Plant Size of (No. Units x Unit Size)		1 x 1000
Total Plant Cost (December, year Z-1 $)		835
Total Plant Investment[a]		865
Start up, Inventory, Land (December, year Z-1 $)		31
Total Capital Requirement (December, year Z-1 $) In Service		896
Operating and Maintenance Costs, (December, Year Z-1 $)		
Fixed	($/kW-yr)	15.1
Incremental		
Variable	(mills/kWh)	0.9
Consumables	(mills/kWh)	0.4
Fuel Cell Replacement (5-yr. life)	($/kW)	55
Heat Rate, Btu, kWh		
Full Load		7130
75% Load		6900
50% Load		6900
Average Annual		7130
Unit Availability		
Unplanned Outage Rate		
Planned Outage Rate		
Annual Availability		
Duty Cycle		Base
Minimum Load, %		--
Preconstruction and Licensing Lead Time, Years		3
Design and Construction Time, Years		2
Unit Life, Years		30
Technology Development Rating		2
Design and Cost Estimate Rating		3

---

[a] Includes AFDC and Escalation for a January 1, year Z, Service.

SAMPLE CALCULATION III

TITLE

Break-even investment cost of generating technology using renewable resource fuel.

KEYWORDS

Break-even cost
Tax preferences for renewable resource technology
Inflation
Book life analysis
Short-term analysis
Current-dollar analysis
Constant-dollar analysis

STATEMENT OF PROBLEM

In the development of any technology, an important design constraint is the break-even investment cost of that technology compared to a reasonable alternative. Using current dollars, determine the break-even total capital requirement of a 500-MW renewable resource generating unit if the reasonable alternative is new coal-fired cycling capacity. Repeat using a constant-dollar analysis.

DISCUSSION

A break-even calculation equates the respective revenue requirements of the two technologies and the period of the study. As a first-order approximation, the energy output of the alternatives will be assumed to be equal. If the candidate technology appears attractive, it may be appropriate to make a more accurate study involving a series of production-cost computer runs to determine the impact of the renewable resource on system economic dispatch.

[redacted]

Data(1)	Alternative A(2) Standard Coal Technology	Alternative B(3) Renewable Resource Technology
Energy supplied(4)	(500,000 kW) (8760 h/yr) (0.3 yr) $= 1.314 \times 10^9$ kWh	Same
Heat rate	10,149 Btu/kWh(5)	—
Fuel cost	$1.55/million Btu(6)	—
Incremental O&M	4.0 mills/kWh(6)	1.5 mills/kWh(6)
Fixed O&M	$13.90/kWyr(6)	$10/kWyr(6)
Total capital requirement	$877/kW(7)	To be determined
Service date	Z+8	Z+8
Equipment life	30 years	30 years
Tax recovery period	15 years	10 years(8)

(1) It must be emphasized that the quantities given here are representative values for illustrative purposes only. Economic factors are taken from the tables appended to Chapter B-3. In a real situation, if more specific information is available, that material must be used along with appropriate economic factors from Appendix A of the white pages. All cost estimates are given in December, year Z−1 dollars.

(2) Data for the existing 500 MW coal-fired unit is similar to a unit described in Appendix B of the white pages. A reasonable facsimile of the appropriate Appendix B sheet is included as page B-5-III-14 since the real Appendix B sheet may vary from time to time as conditions change.

(3) This is an estimate based on technical information derived in the hypothetical project.

(4) It is assumed that the capacity factor is 30% for each alternative for each year of the study. In fact, the capacity factor is often higher in the early years of physical life.

(5) The value stated here is the average heat rate for operation at a 70% load level.

(6) Subject, as appropriate, to a real escalation rate (e_r) of 0.8% per year and an inflation rate (e_i) of 6.0% per year.

(7) Total capital requirement for a year Z inservice date that is subject to an inflation rate (e_i) of 6% per year from the reference year until the plant goes into service (capitalized)

(8) Electric utility tax accountants generally agree that until appropriate tax rules are promulgated, a 10 year tax recovery period should be used for emerging technologies involving renewable resources.

SOLUTION

To determine the break-even investment cost, the revenue requirements for the two alternatives are set equal. This can be done over the book life or over a shorter period such as 10 years (see Chapter B-3). A year-by-year analysis would have little meaning in this problem since it would be necessary to address an equivalent investment that changes in each year.

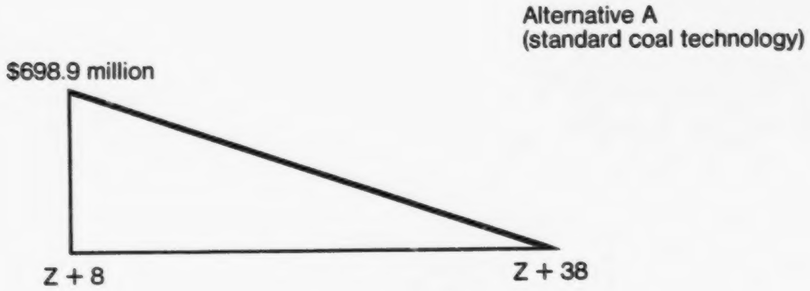
Both a book life analysis and a first-10-year analysis will be made, both beginning at the start of year Z+8, the year when the 500-MW of capacity is required. Even though the information obtained from a book life analysis may be

[redacted]

open to question because of the uncertainties of the future, it is included here because together with the first 10-year analysis, important trends may be brought to light.

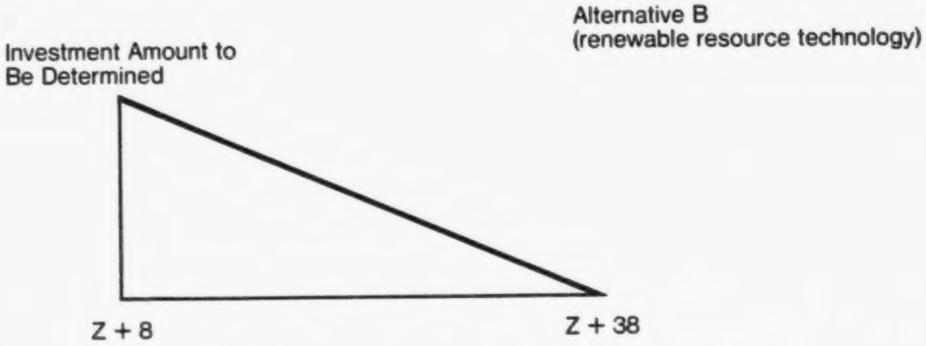
CURRENT DOLLAR ANALYSIS

The time diagrams are presented below:


Alternative A
(standard coal technology)
$698.9 million
Z + 8
Z + 38

Fixed O&M = \$13.90/kW-yr
Incremental O&M = 4.0 mills/kWh
Fuel cost = \$1.55/MBtu
Energy = 1.314×10^9 kWh

Note: All cost estimates are in December, year Z−1 dollars.


Alternative B
(renewable resource technology)
Investment Amount to
Be Determined
Z + 8
Z + 38

Fixed O&M = \$10/kW-yr
Incremental O&M = 1.5 mills/kWh
Fuel cost = —
Energy = 1.314×10^9 kWh

Note: All cost estimates are in December, year Z−1 dollars.

Alternative A Revenue Requirement[1]

Carrying Charges on Investment ($m = 15$, $n = 30$)	Line 1
Fuel Cost Expense	Line 2
Fixed O&M Expense	Line 3
Incremental O&M Expense	Line 4

Alternative B Revenue Requirement[1]

Fuel Cost Expense (renewable resource at zero cost)	--
Fixed O&M Expense	Line 5
Incremental O&M Expense	Line 6
Carrying Charges on Investment ($m = 10$, $n = 30$)	Line 7

---

[1] See calculations below.

The first task is to bring all cost estimates from beginning of year Z dollars to dollars at the beginning of year Z+8 when the capacity is required (see Section B-1.3). Then a book life analysis and a first-10-year analysis will be made.

Line 1

The escalation rate is based on e_i=0.06.

$$\begin{aligned} 1+e_a &= 1+e_i \\ &= 1+0.06 \end{aligned}$$

The total capital requirement is \$877/kW in year Z dollars. In year Z+8 dollars, the TLR for a 500-MW plant would be

$$\begin{aligned} \text{TCR} &= 500{,}000\,(\$877)\,(1.06)^8 \\ &= \underline{\underline{\$698.9 \text{ million}}} \end{aligned}$$

The levelized carrying charge factor, $P_{15,30}$ is from Table III_F.

Line 2.

The apparent escalation rate is based on $e_r = 0.008$ and $e_i = 0.06$

$$\begin{aligned} 1+e_a &= (1+e_r)(1+e_i) \\ &= (1+0.008)(1+0.06) \\ &= 1.0685 \end{aligned}$$

Thus,

$$\begin{aligned} \text{Cost of coal in year Z+8} &= (\$1.55 \text{ million Btu})(1.0685)^8 \\ &= \$2.63 \text{ million Btu} \end{aligned}$$

and

$$\begin{aligned} \text{Annual cost of coal in year Z+8} &= (\$2.63\times10^{-6}/\text{Btu})(10149 \text{ Btu/kWh})(1.314\times10^{9} \text{ kWh}) \\ &= \underline{\underline{\$35.1 \text{ million}}} \end{aligned}$$

Line 3.

The escalation rate is the same as Line 1.

Thus,

$$\begin{aligned} \text{Fixed O\&M expense in year Z+8} &= (\$13.90/\text{kW})(1.06)^8 \\ &= \$22.16/\text{kW} \end{aligned}$$

and

$$\begin{aligned} \text{Annual fixed O\&M expense in year Z+8} &= (\$22.16/\text{kW})(500{,}000 \text{ kW}) \\ &= \underline{\underline{\$11.1 \text{ million}}} \end{aligned}$$

Line 4.

The escalation rate is the same as Line 1.

Thus,

$$\begin{aligned} \text{Incremental O\&M expense in year Z+8} &= (4.0 \text{ mills/kWh})(1.06)^8 \\ &= 6.38 \text{ mills/kWh} \end{aligned}$$

and

$$\begin{array}{r}\text{Annual incremental}\\ \text{O\&M expense}\\ \text{in year Z+8}\end{array} = (6.38\ \text{mills/kWh})\ (1.314 \times 10^{9}\ \text{kWh})$$
$$= \underline{\underline{\$8.38\ \text{million}}}$$

Line 5

The escalation rate is the same as Line 1.

Thus,

$$\begin{array}{r}\text{Fixed O\&M expense}\\ \text{in year Z+8}\end{array} = (\$10/\text{kW})\ (1.06)^{8}$$
$$= \$15.94/\text{kW}$$

and

$$\begin{array}{r}\text{Annual fixed}\\ \text{O\&M expense}\\ \text{in year Z+8}\end{array} = (\$15.94/\text{kW})\ (500{,}000\ \text{kW})$$
$$= \underline{\underline{\$7.97\ \text{million}}}$$

Line 6

The escalation rate is the same as Line 1

Thus,

$$\begin{array}{r}\text{Incremental}\\ \text{O\&M expense}\\ \text{in year Z+8}\end{array} = (1.5\ \text{mills/kWh})\ (1.06)^{8}$$
$$= 2.39\ \text{mills/kWh}$$

and

$$\begin{array}{r}\text{Annual incremental}\\ \text{O\&M expense}\\ \text{in year Z+8}\end{array} = (2.39\ \text{mills/kWh})\ (1.314 \times 10^{9}\ \text{kWh})$$
$$= \underline{\underline{\$3.14\ \text{million}}}$$

Line 7

This is the revenue requirement associated with the unknown total capital requirement of the renewable resource technology.

Book Life Analysis

All costs are in year Z+8 dollars in millions

$$LRR_A = \text{Line } 1 + \text{Line } 2 + \text{Line } 3 + \text{Line } 4$$

$$\begin{aligned} LRR_A &= (\$698.9)P_{15,\,30} + \$35.1L_{30} + (\$11.1 + \$8.38)L_{30} \\ &= (698.9)\,(0.127) + (35.1)\,(2.093) + (19.48)\,(1.886) \\ &= 88.76 + 73.46 + 36.74 \\ &= \$198.96 \end{aligned}$$

The factor $P_{15,\,30}$ for the standard coal technology plant is from Table III_F and a_{30} is from Table II. The levelizing factor for the fuel expense is based on a real escalation rate of 0.8% and inflation of 6.0%, while the levelizing factor for the fixed and incremental O&M expense is based on an inflation rate of 6.0%.

$$LRR_B = \text{Line } 5 + \text{Line } 6 + \text{Line } 7$$

$$\begin{aligned} LRR_B &= (7.97 + 3.14)L_{30} + X \\ &= (11.11)\,(1.886) + X \\ &= 20.95 + X \end{aligned}$$

Again, the levelizing factor from Table III is based on only an inflation rate of 6%.

Equating LRR_A to LRR_B and solving for X,

$$\begin{aligned} X &= 198.96 - 20.95 \\ &= \underline{\underline{\$178.01 \text{ million}}} \end{aligned}$$

Then, using a carrying charge factor from Table III_N based on a 10-year tax recovery period, the break-even investment cost of the renewable resource technology plant would be

$$\begin{aligned} \text{Breakeven investment} &= \frac{178.01}{P_{10,\,30}} \\ &= \frac{178.01}{0.120} \\ &= \underline{\underline{\$1483.42 \text{ million}}} \\ \text{or } &= \$2967/\text{kW in year Z+8 dollars} \\ \text{or } &= \$1862/\text{kW in year Z dollars} \end{aligned}$$

[redacted]

The $1862/kW is comparable to $877/kW for Alternative A. If the more favorable tax rate were not available to the renewable resource technology, the break-even cost would be $1759/kW, using Table III_F.

Short-Term Analysis

A first 10-year analysis is set up in a similar fashion. Again, all costs are in year Z+8 dollars in millions.

$$\begin{aligned}\text{1st 10 year LRR}_A &= (\$698.9)\,P_{10,\,15,\,30} + \$35.1L_{10} + (\$11.1 + \$8.38)L_{10} \\ &= (698.9)\,(0.154) + (35.1)\,(1.392) + (19.48)\,(1.335) \\ &= 107.63 + 48.86 + 26.00 \\ &= \underline{\underline{\$182.48}}\end{aligned}$$

$$\begin{aligned}\text{1st 10 year LRR}_B &= (\$7.97 + \$3.14)L_{10} + X \\ &= (11.11)\,(1.335) + X \\ &= \underline{\underline{14.83 + X}}\end{aligned}$$

Equating LRR_A to LRR_B and solving for X,

$$\begin{aligned}X &= 182.48 - 14.83 \\ &= \underline{\underline{\$167.66 \text{ million}}}\end{aligned}$$

Following the procedure of the book life analysis, this revenue requirement is equivalent to an investment of $1461/kW in year Z dollars or $1366/kW if the more favorable tax rate were not available to the renewable resource.

SUMMARY OF CURRENT-DOLLAR ANALYSIS

	Breakeven Total Capital Requirement of the Renewable Resource Technology (Alternative B) in Year Z Dollars	
	10 Yr Tax Rec.(1)	*15 Yr Tax Rec.*
Book life analysis	$1862/kW	$1759/kW
First 10 year analysis	1461	1366

(1) Electric utility tax accountants generally agree that until appropriate tax rules are promulgated, a 10 year tax recovery period should be used for energy technologies involving renewable resources.

Any of these numbers can be compared directly to the investment cost of Alternative A of $877/kW.

Note that in general a first-10-year analysis produces more conservative results than a book life analysis because of the greater relative magnitude of carrying charges compared to expenses in the early years. The above summary indicates that the break-even total capital requirement of Alternative B would vary from $1366/kW to $1862/kW depending upon the length of the study and the tax treatment anticipated for the renewable resource technology.

CONSTANT DOLLAR ANALYSIS

A constant-dollar analysis is similar to a current-dollar analysis except that the effect of inflation is not included. All estimates of the data section (above) of this sample problem apply including the total capital requirement of Alternative A.

The time diagrams will not be repeated, and the analysis will be performed only over the book life.

Alternative A Revenue Requirement[1]

Carrying Charges on Investment	Line 1
Fuel Cost Expense	Line 2
Fixed O&M Expense	Line 3
Incremental O&M Expense	Line 4

Alternative B Revenue Requirement[1]

Fuel Cost Expense (renewable resource at zero cost)	--
Fixed O&M Expense	Line 5
Incremental O&M Expense	Line 6
Carrying Charge on Investment	Line 7

---

[1] See calculations below.

[redacted]

The first task will be to bring all cost estimates from beginning of year Z dollars to dollars at the beginning of year Z+8 when the capacity is required (see Section B-1.3). This is an easier procedure than in a current-dollar analysis because the apparent escalation applies to only those expenditures that are affected by real escalation.

Line 1

The total capital requirement of \$877/kW in year Z would be unchanged in year Z+8 in a constant dollar analysis.

Thus,

$$\begin{aligned}\text{TCR in year } Z+8 &= (\$877/\text{kW})\ (500{,}000\ \text{kW})\\ &= \underline{\underline{\$438.5\ \text{million}}}\end{aligned}$$

Line 2

The apparent escalation rate is based on $e_r=0.008$

$$\begin{aligned}1+e_a &= 1+e_r\\ &= 1+0.008\end{aligned}$$

Thus,

$$\begin{aligned}\text{Cost of coal in year } Z+8 &= (\$1.55\ \text{million})\ (1.008)^8\\ &= \$1.65/\text{million Btu}\end{aligned}$$

and

$$\begin{aligned}\text{Annual cost of coal in year } Z+8 &= (\$1.65 \times 10^{-6}/\text{Btu})\ (10149\ \text{Btu/kWh})(1.314 \times 10^9\ \text{kWh})\\ &= \underline{\underline{\$22.0\ \text{million}}}\end{aligned}$$

Line 3

Since there is no inflation in a constant dollar analysis,

$$\text{Fixed O\&M expense in year } Z+8 = \$13.90/\text{kW}$$

and

$$\begin{aligned}\text{Annual fixed O\&M expense in year } Z+8 &= (\$13.90/\text{kW})\ (500{,}000\ \text{kW})\\ &= \underline{\underline{\$6.95\ \text{million}}}\end{aligned}$$

[redacted]

Line 4

In the absence of inflation,

$$\begin{aligned}\text{Incremental O\&M}\\ \text{in year } Z+8 &= 4.0 \text{ mills/kWh}\end{aligned}$$

and

$$\begin{aligned}\text{Annual incremental O\&M}\\ \text{in year } Z+8 &= (4.0 \text{ mills/kWh})\ (1.314 \times 10^{9} \text{ kWh})\\ &= \underline{\underline{\$5.26 \text{ million}}}\end{aligned}$$

Line 5

In the absence of inflation,

$$\begin{aligned}\text{Fixed O\&M expense}\\ \text{in year } Z+8 &= \$10/\text{kW}\end{aligned}$$

and

$$\begin{aligned}\text{Annual fixed}\\ \text{O\&M expense}\\ \text{in year } Z+8 &= (\$10/\text{kW})\ (500{,}000)\\ &= \underline{\underline{\$5.0 \text{ million}}}\end{aligned}$$

Line 6

In the absence of inflation

$$\begin{aligned}\text{Incremental O\&M}\\ \text{expense in year } Z+8 &= 1.5 \text{ mills/kWh}\end{aligned}$$

and

$$\begin{aligned}\text{Annual incremental}\\ \text{O\&M expense}\\ \text{in year } Z+8 &= (1.5 \text{ mills/kWh})\ (1.314 \times 10^{9} \text{ kWh})\\ &= \underline{\underline{\$1.97 \text{ million}}}\end{aligned}$$

[redacted]

Line 7

This is the revenue requirement associated with the unknown total capital requirement of the renewable resource technology.

Book Life Analysis

All costs are in year Z+8 dollars in millions.

$$\begin{aligned} LRR_A &= (\$438.5)\,P_{15,30} + \$22.0L_{30} + (\$6.95 + \$5.26) \\ &= (\$438.5)\,(0.072) + (22.0)\,(1.110) + (12.21) \\ &= 31.57 + 24.42 + 12.21 \\ &= \underline{\$68.20} \end{aligned}$$

The factor $P_{15,30}$ is from Table VI_F and L_{30} from Table V. The levelizing factor for the fuel expense is based on a real escalation rate of 0.8% while the fixed and incremental O&M expense, in the absence of inflation, require no levelizing factor.

$$\begin{aligned} LRR_B &= \$5.00 + \$1.97 + X \\ &= \$6.97 + X \end{aligned}$$

Again, in a constant dollar analysis, fixed and incremental O&M does not require a levelizing factor.

Equating LRR_A to LRR_B and solving for X,

$$\begin{aligned} X &= 68.20 - 6.97 \\ &= \underline{\underline{\$61.23 \text{ million}}} \end{aligned}$$

Then, using a carrying charge factor from Table VI_N based on a 10-year tax recovery period, the break-even investment would be

$$\text{Breakeven investment} = \frac{61.23}{P_{10,30}}$$

$$= \frac{61.23}{0.070}$$

$$\text{Breakeven investment} = \$874.71 \text{ million}$$

$$\text{or} = \$1749/\text{kW}$$

The $1749/kW is comparable to $877/kW for Alternative A. If the more favorable tax rate were not available to the renewable resource technology, the break-even cost would be $1701/kW, using Table VI_F.

GENERATING TECHNOLOGIES DATA SHEET

Generation Type: Coal-Steam with Wet Limestone FGD
Geographic Region: East Central

Unit Size, Net Electrical Output, MW(e)	500
Available for Commercial Orders, Year	Current
First Commercial Service, Year	Current

Unit Capital Costs, $/kW, based on Plant Size of (No. Units x Unit Size)	2 x 500
Total Plant Cost (December, year Z-1 $)	803
Total Plant Investment[a]	834
Start up, Inventory, Land (December, year Z-1 $)	43
Total Capital Requirement (December, year Z-1 $)	877

Operating and Maintenance Costs (December, year Z-1 $)

Fixed	($kW-yr)	13.9
Incremental		
Variable	(mills/kWh)	1.0
Consumables	(mills/kWh)	3.0

Heat Rate, Btu,kWh

Full Load	9853
75% Load	9952
50% Load	10448
Average Annual for 70% Load Operation	10149

Type of Operation (nominal)	Base/Int.
Minimum Load, % of Full Load	25
Preconstruction and Licensing lead Time, Years	2
Design/Construction Time, Years	5
Unit Life, Years	30
Technology Development Rating	5
Design, Cost Estimate Rating	3

---

[a] Includes AFDC and Escalation for a January 1, year Z, Service.

[redacted]

SAMPLE CALCULATION IV

TITLE

Determination of total plant investment (TPI) for a given startup date.

KEYWORDS

Overnight construction costs
Allowance for funds during construction
Interest during construction
Inflation
Progress payments
Total plant cost
Total plant investment

STATEMENT OF PROBLEM

When calculating the revenue requirement associated with a new plant item, it is necessary to know the TPI (see Chapter 3). This is one component of the total capital requirement--the dollar amount that will be capitalized on the books of the utility. TPI is usually derived from the total plant cost (TPC), which is an estimate of what it would cost to complete all fabrication and erection tasks, assuming that these tasks are each performed simultaneously and instantaneously. TPC is stated in dollars at a single point in time and is sometimes referred to as the overnight construction cost.

Determine the total plant investment for a generating unit with a total plant cost of \$500 million, assuming a 5-year construction schedule (A) with equal progress payments and (B) with a 5%, 15%, 30%, 35%, 15% progress payment schedule. Then, assuming that the TPC was estimated in December, year Z-1 dollars, determine the TPI for each alternative if the service date is the start of year Z+2.

DISCUSSION

To compute the total plant investment, take the total plant cost and de-escalate each of the individual progress payments to the time that those payments would be made. Then, allow the payments to accumulate annual allowance for funds during construction (AFDC) charges, compounded at the cost of money, until the plant service date.

An examination of the following time diagram will indicate that the final progress payment is made on the date of the TPC.

Data[1]	Start of Year	Progress Payments[2]	
		Alternative A	Alternative B
	Z−4	$100[3]	$ 25[3]
	Z−3	100	75
	Z−2	100	150
	Z−1	100	175
	Z	100	75
		$500	$500
Inflation rate		6%	6%
Cost of money		10%	10%

---

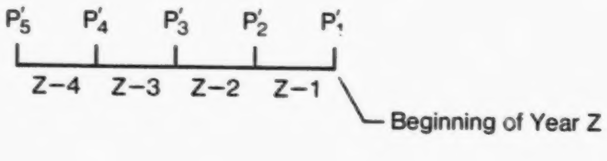
[1] It must be emphasized that the quantities given here are representative values for illustrative purposes only. Economic factors are taken from the tables appended to Chapter B-3 of the yellow pages. In a real situation, if more specific information is available, that material must be used along with appropriate economic factors from Appendix A of the white pages.

[2] Progress payments, given in the statement of the problem are in December, year Z−1 dollars, the date of the TPC.

[3] In millions of dollars.

SOLUTION

The time diagram is presented below.



1. Determine P_j from payment schedule
2. De-escalate P_j to P_j'

$$P_j' = \frac{P_j}{(1+e_a)^{j-1}}$$

3. Compound P_j' to P_j'' in year Z to include effect of AFDC

$$\begin{aligned} P_j'' &= P_j' \, (1+i)^{j-1} \\ &= P_j \left(\frac{1+i}{1+e_a}\right)^{j-1} \end{aligned}$$

$$TPI = \sum_{j=1}^{n} P_j''$$

where $j = 1$ for year Z
$j = 2$ for year Z−1
.
.
.
$j = 5$ for year Z−4

In this sample problem,

$$\begin{aligned} \frac{1+i}{1+e_a} &= \frac{1+0.10}{1+0.06} \\ &= 1.0377 \end{aligned}$$

Thus,

$$\begin{aligned} TPI_A &= \$100 \, [1+1.0377+(1.0377)^2+(1.0377)^3+(1.0377)^4] \\ &= 100 \, [5.391] \\ &= \underline{\underline{\$539.1}} \\ TPI_B &= \$75+175 \, (1.0377)+\$150 \, (1.0377)^2+\$75 \, (1.0377)^3 \\ &\quad +\$25 \, (1.0377)^4 \\ &= \underline{\underline{\$530.9}} \end{aligned}$$

Note that the two payment schedules result in essentially the same TPI. Payment Schedule B is typical of a fossil-fired generating unit, so that in most cases the assumption of equal payments (Schedule A) will produce acceptable results.

Finally, the problem asks to move each TPI from year Z to year Z+2 to reflect a change in service date. In this case, the movement of funds is to establish a new reference year and not to compare money in different years. Section B-1.3 shows that the apparent escalation rate is to be used in this case.

Thus,

$$
\begin{aligned}
\text{TPI}_A \text{ in year Z+2} &= (\text{TPI}_A \text{ in year Z})\,(1.06)^2 \\
&= (\$539.1)\,(1.124) \\
&= \underline{\underline{\$605.95}} \\
\text{TPI}_B \text{ in year Z+2} &= (\text{TPI}_B \text{ in year Z})\,(1.06)^2 \\
&= (\$530.9)\,(1.124) \\
&= \underline{\underline{\$596.73}}
\end{aligned}
$$

GLOSSARY OF TERMS

ALLOWANCE FOR FUNDS DURING CONSTRUCTION (AFDC)

Allowance for Funds During Construction (sometimes called Interest During Construction) as used in TAG, represents the time value of money during construction and is based on an interest rate equal to the weighted cost of capital. This interest is compounded on an annual basis (end of year) during the construction period or all funds spent during the year or previous years. (AFDC as used in TAG is not the AFDC change used in rate making or electric utility accounting systems. The AFDC charge as used in accounting systems often represents an income account and is generally computed at a lower interest rate [sometimes simple interest] than the incremental cost of money).

AMORTIZE

To recover or pay back, on a regular schedule, a sum of money.

ANALYSIS, BOOK LIFE

A present value (or levelized) revenue requirement analysis carried over the entire book life.

ANALYSIS, BREAK-EVEN

A determination of the year in which the cummulative present value of revenue requirements of two alternatives are equal.

ANALYSIS, SHORT-TERM

A present value (or levelized) revenue requirement analysis carried over a period shorter than the book life.

ANALYSIS, YEAR-BY-YEAR

A revenue requirement analysis in which expenditures are compared year-by-year into the future rather than present valued or levelized.

ANNUITY

A series of equal annual payments occurring over a period of time.

AVAILABLE FOR COMMERCIAL ORDERS

The earliest time that a commercial order can be placed for a new technology with reasonable confidence for acceptable economic and technical performance.

BIAS

Conscious or subconscious discrepancies between a person's response and an accurate description of his underlying experience and knowledge.

BOOK

A general term that connotates the financial records of a company, usually related to rate making and investment matters.

BOOK LIFE

The years of service expected of an investment, which for EPRI purposes, is the period over which an investment amount is recovered through book depreciation.

CAPACITY, RATED

The maximum capacity which a generating unit can sustain over a specified period of time. The capacity may be stated as net or gross. Unless otherwise stated, all capacity data in this Guide are stated as net.

CAPACITY FACTOR

The total energy output over a period of time in hours divided by the product of the period hours and the unit capacity. The capacity factor can be computed on either a net or gross basis. Unless otherwise stated, all capacity factor data in this Guide are stated as net.

CAPITAL INVESTMENT

See Investment.

CAPITALIZE

To place an investment on the books of a company.

CAPITALIZATION

The total of all debt and equity money in a utility company.

CARRYING CHARGES

The revenue needed to support an investment and equal to the sum of

Return on Debt
Return on Equity
Income Taxes
Book Depreciation
Property Tax
Insurance

CARRYING CHARGE FACTOR (RATE)

The amount of revenue per dollar of investment that must be collected from customers in order to pay the carrying charges on that investment. The carrying charge factor (rate) is expressed as a decimal that is multiplied by the original investment to obtain a dollar amount. The carrying charge rate can be a present value or levelized quantity, over a specified period of time (up to the book life), or an annual quantity in a specific year of life.

COMMERCIAL OPERATION DATE

The date that is related to the satisfactory completion of acceptance tests as specified in the contract with the vendor. Often, the Commercial Operation Date and the Service Date coincide.

COMMON STOCK

A type of equity security in which the holder is a part owner in the company. This is the most speculative type of security usually sold by a utility and pays the highest relative return, but is the last to receive a payment and has the lowest priority in the case of liquidation. There is no guarantee that the company will ever pay any return (dividend) to the common stock holder.

CONCEPTUAL ENGINEERING DESIGN

A plant design for a new technology based on technical concepts that have not been demonstrated on an integrated commercial scale. Often only limited experimental data are available, and the design and cost estimate are very approximate.

CONSERVATION (ELECTRICAL)

The reduction in the use of electricity by consumers through some overt action.

CONSTANT DOLLAR ANALYSIS

An analysis made without including the effect of inflation although real escalation is included. The discount rate in the absence of inflation (see Section B-2.7) must be used.

COST RECOVERY TAX DEDUCTION

The deduction that is permitted under the Internal Revenue Code in the calculation of taxable income. Cost Recovery for tax purposes, while similiar in nature to the book depreciation entry for rate making purposes, is not of itself a component of the carrying charge and therefore is not a revenue requirement.

COST OF DEBT MONEY

The amount paid to the holders of debt securities for the use of their money. The magnitude is stated on the debt certificate (contract) and is independent of future financial conditions including expected future inflation. In this Guide, it is the average cost of future debt financing.

COST OF EQUITY MONEY

The earnings expected by an investor when purchasing equity shares in a company. The magnitude may vary depending on the financial condition of the company and inflation.

COST OF MONEY

The return required by investors in order to attract investment capital. It is numerically equal to the sum of Return on Debt and Return on Equity and is the time value of money or the discount rate used in present worth arithmetic.

CURRENT DOLLAR ANALYSIS

An analysis that includes the effect of inflation and real escalation. The discount rate is the Cost of Money.

DEBENTURE

A type of debt security in which the holder has given a loan to a company with only the company's reputation (IOU) as collateral. This is the second most secure (behind the first mortgage bond) form of security usually offered by a utility and pays the second lowest relative return. It has the second highest priority in the case of liquidation.

DEBT MONEY

That portion of a company's total capitalization resulting from the sale of first mortgage bonds and debentures.

DEBT RATIO

The ratio of debt money to total capitalization.

DECISION ANALYSIS

The evaluation of decision options and the estimation of the value of additional information or testing, using the time and risk preferences of the decision maker.

DEFERRED INCOME TAX

The portion of the total income tax liability that may be deferred to a future date. For TAG purposes, a deferred tax occurs when a cost recovery schedule is used that is different from the straight-line depreciation schedule that is used for rate making purposes.

DEMAND

The rate at which electric energy is delivered, expressed in units of power, such as kilowatts, at a given instant (indicated) or averaged (integrated) over a designated period of time. In the utility industry, it is common to express demand as one hour integrated.

DEPRECIATION

The accounting mechanism for the reduction in value of a sum of money. The precise definition and the schedule of reduction will vary widely depending upon the use.

DEPRECIATION, ACCELERATED

Any schedule of depreciation that reduces a sum of money more rapidly than would be done with straight-line depreciation.

DEPRECIATION, BOOK

A component of the carrying charge and is the revenue required to repay the original investment. In the utility industry, it is usually calculated on a straight-line basis.

DEPRECIATION, TAX

A term made obsolete by the Economic Recovery Tax Act of 1981. See Cost Recovery Tax Deduction.

DETAILED ENGINEERING DESIGN

A design that includes sufficient detail, based on previous commercial or extensive pilot plant operating experience, to produce definitive cost estimates for commercial plant construction.

DISCOUNT RATE

See Cost of Money.

DISPATCHING

The operating control of an integrated electric system involving operations such as:

1. The assignment of levels of output to specific generating units or load control devices to effect the most reliable and economical supply as the loads rise or fall.

2. The control of the operation of high-voltage lines, substations, and equipment.

3. The scheduling of various types of transactions with other electric utilities over the interconnecting transmission lines.

EARNINGS

That portion of revenue that remains after all charges, including interest, have been satisfied.

ENERGY EFFICIENCY

The ratio of the useful energy delivered by a system to the energy supplied to it.

ENERGY STORAGE

The mechanism of utilizing electricity during the peak load period that was stored during light load period when energy production costs were relatively low. The duration of an energy storage cycle rarely exceeds one week.

EQUITY

That portion of a company's total capitalization resulting from the sale of common and preferred stock and retained equity earnings.

EQUITY RATIO

The ratio of equity money to total capitalization. It is also equal to

one minus the debt ratio.

ESCALATION, APPARENT

The total annual rate of increase in cost. The apparent escalation rate includes the effects of inflation and real escalation.

ESCALATION, REAL

The annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements and in design or manufacturing (negative rate). The real escalation rate does not include inflation (see Escalation, Apparent).

EXPECTED VALUE

The average or representative value of a variable, neglecting uncertainty and risk considerations.

EXPENDITURE

An outlay of money for either expense or investment purposes.

EXPENSE

A general component of revenue requirement used, for EPRI purposes, for goods and services that are usually utilized in one year or less. Examples include:

fuel
operation
maintenance

FIRST COMMERCIAL SERVICE

The earliest time of initial commercial service of a new technology if an order was placed on the first date that the technology was available for commercial orders.

FIRST MORTGAGE BOND

A type of debt security in which the holder has given a loan to a company with undefined physical assets used as collateral. This is the most secure form of security usually offered by a utility and pays the lowest relative return. It has the highest priority in the case of liquidation.

FLOW THROUGH

An accounting practice in which deferred income taxes are passed on immediately either to the rate payers through a decrease in rates or to the stockholders through an increase in earnings (Return on Equity). It is the opposite of Normalization accounting.

FUND FOR CONSTRUCTION

The general fund that provides the monies needed to purchase new investments. The sources are:

1. Book depreciation

2. Retained return on equity

3. Deferred income taxes

4. New debt and equity financing

HEAT RATE

The amount of energy expressed in Btu required to produce a kWh of electric energy. Heat rates in the TAG are expressed as the higher heating value (HHV) for fossil fuel burning technologies.

HEAT RATE, AVERAGE

The heat rate for a unit operated in its normal manner for a stated period of time based on the higher heating value of the fuel used.

HEAT RATE, FULL LOAD

The heat rate for a unit operated at rated capacity, based on the higher heating value of the fuel used.

HIGHER HEATING VALUE

Higher heating value (HHV) is the thermal energy produced in Btu/lb of fuel from completely burning the fuel to produce carbon dioxide and liquid water. The lower heating value (LHV) does not include the latent heat of condensation of the water produced. In the Technical Assessment Guide all fuel heat values and plant heat rates are based on the higher heating value. The higher heating value is sometimes referred to as the gross heating value (GHV).

GENERATING STATION

The location of some combination of prime mover electric generators and necessary ancillary equipment that are used to obtain electric energy by the conversion of another form of energy.

INFLATION

The rise in price levels caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal quality. Inflation does not include real escalation (see Escalation, Apparent).

INSTALLATION DATE

The date that a facility is first connected or synchronized to the system. This date must not be confused with the Service Date.

INTEREST DURING CONSTRUCTION (IDC)

See Allowance for Funds During Construction.

INTERNAL CASH GENERATION

The process in which more money is collected as revenue from customers than that which is needed to pay operation costs during a period of time. The internally generated cash is used to purchase new investments and includes:

1. Book depreciation
2. Retained return on equity
3. Deferred income taxes (assuming normalization accounting procedures)

ITEM

See Investment.

INVESTMENT

An expenditure which results in a unit of plant that would be of long term use to a company. For EPRI purposes in an economic analysis, the money to pay for an investment comes from new debt and equity financing and is amortized through the Book Depreciation charge.

INVESTMENT TAX CREDIT

An immediate reduction in income taxes equal to a percentage of the installed cost of a new investment.

INTEGRATED DEMONSTRATION PLANT

An initial facility of sufficient size to verify a design as the last step prior to building the first commercial unit.

LEVELIZATION

The use of present worth arithmetic to convert a series of transactions to an equivalent annuity.

LEVELIZED CAPACITY FACTOR

A constant annual capacity factor for a generating unit such that the total present worth of the energy produced during the analysis period using the constant annual capacity factors is the same as the present worth of the energy produced by the individual annual capacity factors.

LOAD DURATION CURVE

A chart showing electric demand in decreasing magnitude plotted against total duration of occurrence.

LOAD FACTOR

The ratio of the actual energy consumed during a designated period to the energy that would have been consumed if the peak load were to exist throughout the designated period. The term, load factor, is used to describe a characteristic of individual or aggregated load rather than that of generation.

LOAD MANAGEMENT

The application of measures to influence the customer's use of electricity so as to modify demand and load factor.

LOAD PROFILE CURVE

A chart showing chronological electric demand plotted against time of occurrence. It illustrates the varying magnitude of the load during the period covered.

LOSS OF LOAD PROBABILITY (LOLP)

The proportion of time that the available generation is expected to be unable to meet the system load.

NORMALIZATION

An accounting practice in which deferred income taxes are accumulated in a reserve account and effectively used to purchase new investments. The rate base is reduced by the accumulated reserve. It is the opposite of Flow Through accounting.

OVERNIGHT CONSTRUCTION

See Total Plant Cost.

PHYSICAL LIFE

See Book Life.

PILOT FACILITY

A small-scale facility based on a flexible design for studying a range of process conditions and providing a basis for optimum design of the demonstration or full size facility.

PLANT ITEM

See Investment.

PREFERRED STOCK

A type of equity security in which the holder is a part owner in the company. This is the second most speculative type of security and usually carries a promise to pay a stated return, if a return is paid. No return on common stock can be paid until return on preferred stock has been paid. Preferred stock has the second lowest priority in the case of liquidation.

PRELIMINARY ENGINEERING DESIGN

A detailed, conceptual engineering design that is developed from an experimental data base. The preliminary design reduces the uncertainty in the equipment size and costs. If the development of the technology proceeds, the preliminary engineering design is the basis for the detailed engineering design.

PRIME MOVER

The engine, turbine, water wheel, or similar device that drives an electric generator.

RATE BASE

That portion of total assets (principally investments in plant and equipment), as defined by a rate regulatory body, upon which a utility is allowed to earn a return.

RETURN ON DEBT

A component of the carrying charge and is the revenue required to pay for the use of debt money. It is usually stated as a percentage and is applied to the unrecovered capital in a particular year. Numerically it is equal to the Cost of Debt Money times the Debt Ratio.

RETURN ON EQUITY

A component of the carrying charge and is the revenue required to pay for the use of equity money. It is usually stated as a percentage and is applied to the unrecovered capital in a particular year. Numerically it is equal to the Cost of Equity Money times the Equity Ratio.

REVENUE REQUIREMENT

The amount of money that must be collected from customers to compensate a utility for all expenditures associated with the implementation of an alternative decision.

SENSITIVITY ANALYSIS

The identification of variables within a reasonable range of uncertainty that can reverse or modify a decision.

SERVICE DATE

The date that a facility is declared available for normal operation and the Total Capital Requirement is capitalized. Often, the Service Date and the Commercial Operation Date coincide.

SUBJECTIVE UNCERTAINTY

A probabilistic distribution representing a person's beliefs about the value of a variable, based on that person's experience and knowledge.

SUNK COST

Any cost incurred when a prior decision is made and which cannot be affected by the current course of action.

TAXABLE INCOME

That portion of revenue remaining after all deductions permitted under the Internal Revenue Code and a State Revenue Code have been taken.

TAX RECOVERY CLASS

One of several classes that determines the period of time over which the cost recovery tax deduction occurs. See Cost Recovery Tax Deduction.

TAX LIFE

A term made obsolete by the Economic Recovery Tax Act of 1981. See Tax Recovery Class.

TAX PREFERENCES

Incentives designed to encourage investment as a stimulus to the overall economy. In this Guide, deferred income taxes and the investment tax credit are tax preferences.

TAX RATE

The rate applied to taxable income to determine Federal and state income taxes.

TOTAL CAPITAL REQUIREMENT (TCR)

The money that is placed (capitalized) on the books of the utility on the service date. TCR includes Total Plant Investment plus capitalized plant startup, fuel inventory, and land costs. See Table 3-1.

TOTAL PLANT COST (TPC)

The total of all direct and indirect construction costs including engineering, overheads, fees, and contigencies expressed in dollars at a single point in time. TPC is often called an overnight construction cost. See Table 3-1.

TOTAL PLANT INVESTMENT (TPI)

The Total Plant Cost as modified by escalation and Allowance for Funds During Construction (AFDC). TPI is referred to the service date of the plant. See Table 3-1.

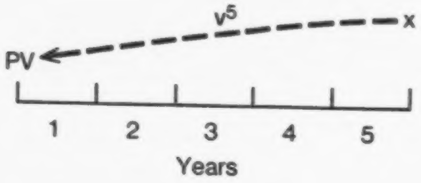
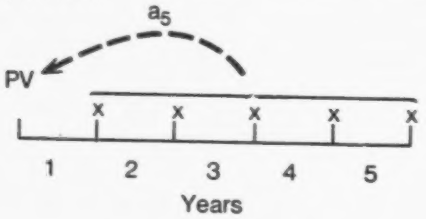
VALUE OF INFORMATION

The change in value brought about by reducing the uncertainty in variables that can change a decision.

WEIGHTED COST OF CAPITAL

See Cost of Money.

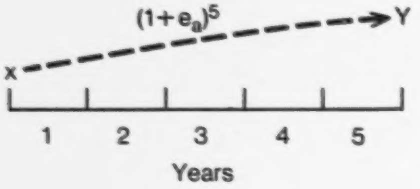
COMPENDIUM OF SYMBOLS

	The discount rate or the time value of money in the time period n. See also Cost of Money.
$v^n = \frac{1}{(1+i)^n}$	The present worth factor for a single payment made n time periods in the future at a discount rate of i per time period.
$PV = xv^5$	
$a_n = v + v^2 + \cdots + v^n$	The present worth factor for a uniform series that extends for n years in the future at a discount rate of i per time period.
$PV = xa_5$	 a_5 PV x x x x x 1 2 3 4 5 Years
$\frac{1}{a_n}$	The capital recovery factor of a uniform series is the reciprocal of the a_n factor.
e_i	The annual inflation rate is the rise in price levels caused by an increase in available currency and credit without a proportionate increase in available goods and services of equal quality.
e_r	The real annual escalation rate is the annual rate of increase of an expenditure that is due to factors such as resource depletion, increased demand, and improvements in design or manufacturing (negative rate). The real escalation rate does not include inflation.

$$e_a = [(1+e_r)(1+e_i)] - 1$$

The apparent annual escalation rate is the total annual rate of increase in cost and includes the effects of both inflation and real escalation.

$$Y = x(1+e_a)^5$$



NOTE: To express a payment subject to escalation, the apparent escalation rate is used. To determine the present worth of a payment in a reference year, the discount rate is used.

$$L_n = \frac{k(1-k^n)}{a_n(1-k)}$$

The levelization factor, $\underline{L}_n$ computes the equivalent levelized payment of a series of payments made over $\underline{n}$ periods that are subject to a constant apparent escalation.

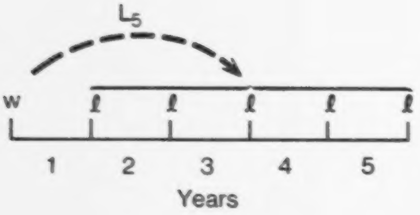
where

$$k = \frac{1-e_a}{1-i}$$

$$a_n = \frac{(1+i)^n - 1}{i(1+i)^n}$$

$$e_a = (1+e_r)(1+e_i) - 1$$

$$\ell = w\,L_5$$



debt ratio

The debt ratio is the total amount of debt money divided by the total capitalization.

equity ratio

The equity ratio is the total amount of equity money divided by the total capitalization. It is also equal to

$$1-\text{debt ratio}$$

R_D	The debt return is the cost of debt money times the debt ratio.
R_E	The equity return is the cost of equity money times the equity ratio.
COM	The cost of money is the sum of the debt return and the equity return and is equal to the discount rate, i.
c	Weighted cost of capital in the absence of inflation. $i = (1+c)(1+e_i) - 1$
D_B	Book depreciation is the annual charge against revenue used to repay the original amount obtained from investors. In the utility industry, straight line depreciation is usually used. Thus, for a plant item with an n year book life, $D_B = \frac{\text{Investment}}{n}$
t	The income tax rate.
T	Income taxes equal to t times taxable income.
CR	Cost Recovery Tax Deduction is the appropriate cost recovery deduction allowed by the Internal Revenue Service for computing taxable income.
CC	Carrying Charges are the revenue needed to support an investment item and equals sum of return on debt, return on equity, income taxes, book depreciation, property taxes (PT), and insurance (I). $CC = R_D + R_E + T + D_B + PT + I$
RR	Revenue Requirement is the total revenue that must be collected from customers to compensate a utility for all expenditures associated with the implementation of an alternative decision involving money. $RR = CC + \text{Expenses}$
CC_t	The actual carrying charge (not levelized) in the t^{th} year of life of an investment item.

$V_{m,n}$	The present value of carrying charges of a plant item with a tax recovery class of m years and a book life of n years. $V_{m,n} = CC_1v^1 + CC_2v^2 + \ldots + CC_nv^n$
$P_{m,n}$	The annual carrying charge, levelized over the n year book life, of a plant item with a tax recovery class of m years and a book life of n years. $P_{m,n} = \frac{V_{m,n}}{a_n}$
$V_{f,m,n}$	The present value of carrying charges over the first f years of life of a plant item with a tax recovery class of m years and a book life of n years. $V_{f,m,n} = CC_1v^1 + CC_2v^2 + \ldots + CC_fv^f$ where $f < n$
$P_{f,m,n}$	The annual carrying charge, levelized over the first f years of life of the present value of carrying charges over the first f years of life of a plant item with a tax recovery class of m years and a book life of n years. $P_{f,m,n} = \frac{V_{f,m,n}}{a_f}$

INDEX

Allowance for funds during constitution 3-4
Analysis
  Book life, levelized 1-8, B-3-3, B-3-7
  Book life, present value 1-7, B-3-3
  Breakeven 1-11, B-3-15
  Short-term 1-9, B-3-5, B-3-13
  Year by year 1-9, B-3-11
Annuity - See Uniform series
Average daily unavailability 4-2, 4-3

Capability ratio 4-2, 4-3
Capital cost, components of 3-13
Carrying charges
  Definition 1-5, B-2-3, B-2-5
  Year by year B-3-2
Computer program listings of ECONCC and ECONLN B-3-A-20
Constant dollars 1-6, B-1-8
Contingencies 3-3
Current dollars 1-6, B-1-8
Cost estimating premises
  Cost estimates 3-1
  Operating costs 3-9
  Total capital requirement 3-4
  Total plant cost 3-1
  Total plant investment 3-4
Cost estimates, plants - See page App B-1 of Appendix B
Cost of money - See Discount rate
Cost of money in absence of inflation 1-7, B-2-15

Debentures B-2-9
Debt money B-2-9
Depreciation
  Book B-2-6
  Tax - See Tax recovery period
Discount rate 1-4, 1-6, B-2-14

ECONCC computer program listings B-3-A-20
ECONLN computer program listings B-3-A-23
Economic parameters
  Discussion B-3-1
  Actual problems Appendix A-1
  Illustrative purposes for TAG B-3-A-1
Equity money B-2-9
Equivalent availability 4-2, 4-3
Escalation
  Apparent 1-4, B-1-7
  Discussion of 1-4, 1-5, B-1-7, B-1-9, B-2-14
  Real 1-4, B-1-7
Expense 1-5, B-2-2, B-2-4

Flow through B-2-12

Income taxes B-2-10
Inflation 1-4, B-1-6. B-1-7
Interest during construction - See Allowance for funds during construction
Investments 1-5, B-2-4

Levelization 1-4, B-1-9
Loss of load probability (LDLP) 4-1, 4-5, 4-6
Loss factor 6-7
Losses, electrical 6-6

Mortgage bonds B-2-9

Normalization B-2-12

Operating availability 4-2, 4-3
Outage rate
    Equivalent unplanned 4-1, 4-3
    Planned 4-1, 4-3
    Unplanned 4-1, 4-3

Payments, occurrence of 1-7, B-2-17
Plant design premises
    Ambient conditions 2-4
    Cost boundary 2-4
    Duty cycle 2-1
    Emissions 2-9, 2-15
    Fuel system 2-5
    Fuel type 2-7, 2-10 to 2-13
    Fuel variability 2-7
    Load following 2-8
    Location of plant 2-3
    Loss of performance with age 2-8
    Part load performance 2-8
    Size 2-2
    Spare equipment 2-9
    Startup facilities 2-8
    Water analysis 2-8, 2-14
Present value 1-3, 1-7, 1-8, 1-10, B-1-1, B-3-5
Present worth - See Present value
Property tax B-2-14

Regional systems 6-1
Regulation and rate making B-2-16
Return on investment B-2-8
Revenue requirement 1-4, B-2-2

Screening curves 6-4, 6-5
Stock, common & preferred B-2-9
Sunk cost 1-11, B-2-5
Supply planning methods 6-2

Tables of economic factors for actual problems - See page App A-1 of Appendix A
Tables of economic factors for illustrative problems - See B-3-A-1
Tax preferences B-2-13
Tax recovery period B-2-11, B-2-12
Total capital requirement 3-13, 5-1
Total plant cost 3-13
Total plant investment 3-13

Uncertainty information - See Appendix C
Uncertainty, treatment of
    Bibliography B-4-10
    Deterministic analysis B-4-1
    Probabilistic analysis B-4-7
    Sensitivity analysis B-4-2
    Subjective uncertainty B-4-3
    Value of perfect information B-4-8
Uncertainty, sources of 5-3